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Bulgaria
Power Demand and Supply Options

June 22, 1993

Industry and Energy Operations Division
Country Department I
Europe and Central Asia Region

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CURRENCY EQUIVALENTS

Currency unit = lei (plural levy), abbrev. Lv
US$1 = 21 average 1992
US$1 = 23.2 - 23.5. Lv. est. average 1992

MEASURES AND EQUIVALENTS

k (kilo)	= 10^3	Levy (Watt second)	= Joule (J)
M (levy)	= 10^6	J	= 0.239 cal
G (giga)	= 10^9	kcal	= 3.9688 BTU
T (tera)	= 10^{12}	kWh	= 3.8 MJ
A	= Ampere	TOE	= 10.2 Gcal
V	= Volt	TCE	= 7.0 Gcal
W	= Watt	Meter (m)	= 3.28 feet
J	= Joule	Kilometer (km)	= 0.6214 miles
cal	= calorie	Kilogram (kg)	= 2.2 pounds
TOE	= ton of oil equivalent	Metric ton (t)	= 2,205 pounds
TCE	= ton of coal equivalent		
BTU	= British thermal unit		

ACRONYMS

CEC	Commission of European Communities
CMEA	Council of Mutual Economic Assistance
COE	Committee of Energy
COM	Council of Ministers
COMGEO	Committee of Geology and Mineral Resources
CHP	Combined Heat and Power
EIB	European Investment Bank
EBRD	European Bank for Reconstruction and Development
ESS	Energy Strategy Study (Report 10143 Bul)
FCMEA	Former Council of Mutual Economic Assistance (CMEA) Block
FGD	Fuel Gas Desulfurization
FSU	Former Soviet Union
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IPS	Interconnected Power System (of CMEA)
MOF	Ministry of Finance
NDC	National Dispatch Center
NEK	National Electric Company
SAR	Staff Appraisal Report
UCPTE	Union for the Coordination of Production and Transport of Electricity (West European Grid)
UDF	Union of Democratic Forces
USAID	US Agency for International Development
USTDA	US Trade and Development Agency
WANO	World Association of Nuclear Operators
WASP	Wien Automated System Planning Model

FISCAL YEAR

January 1 - December 31

BULGARIA

POWER DEMAND AND SUPPLY OPTIONS

FOREWORD

At the request of the Group of the Seven Industrialized countries (G-7) and with the agreement of the Government of Bulgaria, a joint International Energy Agency (IEA) - World Bank mission visited Bulgaria from November 7 to 20, 1992 to prepare a study which would assess power sector strategies and financing requirements, in order to ensure the reliable supply of electricity if or when nuclear facilities are scheduled for modifications or shutdown for safety reasons. The mission consisted of: A. Kocic (Mission Leader); J. Moose (Economist); L. Mitov (World Bank Resident Mission); G. Kadagatur and S. Virmani (Consultants from the World Bank); J. Pierson (IEA team leader); and A. Wheeler (Consultant from the IEA). The report was written by A. Kocic and J. Moose at the World Bank, in close cooperation with J. Pierson at the IEA and with contributions from other team members.

Mr. L. Radulov, at that time President of the Committee of Energy (COE), provided overall support and guidance, while Mr. Dianko Dobrev, Chairman of the Managing Board of NEK, managed the coordination of work by NEK. The management and staff of COE, NEK, Energoproekt, the Committee for Peaceful Uses of Atomic Energy, and EQE-International, actively participated in the work of the mission.

The first draft of the study was prepared in March 1993, based on the findings of the mission. The draft was discussed with the Bulgarian authorities in March/April 1993. Following these discussions, the study was revised.

The data on costs for safety upgrades at the nuclear units used in this report were provided by NEK with the assistance of outside consultants. They differ somewhat from the nuclear safety cost data used in the Summary Report presented to the G-7, which were provided later by EBRD. The differences, however, are not large and do not affect the overall conclusions.

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July 1, 1993

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SYNOPSIS

The 1992 G-7 summit in Munich requested the World Bank, with the cooperation of the International Energy Agency (IEA), to produce a study of alternative energy sources to replace the less safe nuclear plants (VVER 440 model 230s, RBMKs) in Eastern Europe and the former Soviet Union. This study is specifically of the alternative energy sources in Bulgaria, which has 4 VVER 440 model 230 nuclear units (units 1-4), at its Kozloduy nuclear plant with 1760 MW of gross generating capacity. These units represent about 15% of Bulgaria's generating capacity, but typically 20-25% of generation, since they are base load units. Kozloduy also has 2 VVER 1000 nuclear units (units 5 and 6), each with 1000 MW of generating capacity representing an additional 17% of capacity.

This report assumes that any nuclear power unit which continues to operate over an extended period, undertakes major new investments to upgrade nuclear safety. The report then assesses alternative electricity supply options and their associated costs if Bulgaria were to shut down some or all of its nuclear power units under various accelerated timetables instead of undertaking these major nuclear safety upgrades. The feasibility of early closure of these nuclear plants is dependent on the ability of Bulgaria to: (1) obtain reliable and economic energy supplies (most of which would be imported) to meet future demand; (2) finance internally or obtain external financing for the investments in nuclear safety and non-nuclear generating units which would be required; and (3) manage the short lead times required for investment selection, financing arrangements, design and construction. It is also dependent on the country's willingness to pay the costs involved in nuclear safety upgrades and replacement of nuclear power by alternatives.

Six nuclear electricity supply scenarios, scenarios 0 to 5, were developed by the Bulgarian Government for analysis purposes. These scenarios range from shutting down all nuclear units including the VVER 1000s immediately (scenario 0) to running all units to the end of their design lives after safety upgrading (scenario 5). The other scenarios, 1-4, are in between and involve various closure dates for the 4 VVER 440s ranging from closing all 4 of these units immediately, but continuing to run the VVER 1000s to the end of their design lives after safety upgrades (scenario 1), to closing units 1 and 2 in 1998 and allowing units 3 and 4, as well as the VVER 1000s to continue operations to the end of their design lives after safety upgrades (scenario 4). Also, three electricity demand forecasts for the period 1993 to 2010 (minimum, medium and maximum) were agreed between the Bulgarian Government, the Bank and the IEA. The medium forecast is generally used by the Bulgarian Government for its planning purposes while the minimum or low forecast, which assumes considerable demand side management, is based primarily on work done by the Bank. The maximum or high case was agreed upon as an upper limit. The six nuclear supply scenarios combined with the three demand forecasts create 18 possible cases, for each of which a least cost electricity supply plan was developed.

The main conclusions from the analysis are: (1) it does not appear to be economically feasible to close the VVER 1000 units at Kozloduy (the safer units) though these should undergo safety upgrading; (2) the least cost electricity supply option for Bulgaria is to run all of the nuclear units to the end of their design lives after safety upgrading; (3) it would be technically feasible for Bulgaria to replace some or all of the VVER 440s (the less safe units) with alternative electricity supplies and energy saving measures by the mid to late 1990s; (4) there are several relatively low cost electricity supply alternatives in Bulgaria the most important of which is probably use of highly efficient gas-fired combined cycle generating units especially in existing district heating and industrial generating plants; and (5) the additional cost of replacing the VVER 440s is about 3-20% of total electricity supply costs, depending primarily on how many of them are closed and when they are closed. The Bulgarian Government has expressed concern that the least cost alternatives to nuclear power analyzed above rely too much on electricity generated from imported natural gas and they have recommended that a limit be placed on the use of natural gas for the purposes of this analysis. If this is done, the cost of replacing nuclear power

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I. SUMMARY AND CONCLUSIONS

A. Background

1.01 The 1992 G-7 Munich meeting communique suggested measures related to the safety of the nuclear power plants in the countries of the former Soviet Union and Central and Eastern Europe. The G-7 communique suggested that "*the scope for replacing less safe (nuclear) plants by the development of alternative energy sources and the more efficient use of energy*" should be studied, and "*together with the competent international organizations, in particular the IEA, the World Bank should prepare the required energy studies, including replacement sources of energy and the cost implications*". This study has, therefore, been prepared by the World Bank in cooperation with the IEA, the Government of Bulgaria, and the National Electric Company (NEK) in response to the G-7 request.

B. The Study

1.02 Scope. This study considers possible scenarios developed by the Government of Bulgaria and NEK for the Kozloduy nuclear plant in combination with three forecasts of electricity demand agreed to for the purposes of the study by the Bank, the IEA, the Government of Bulgaria and NEK. For each scenario, most of which involve retirement of one or more of the nuclear reactors at Kozloduy, and demand forecast, the study estimates the least cost alternative supply of electricity. The study does not provide independent judgements as to the safety levels of the nuclear units and does not make safety recommendations.

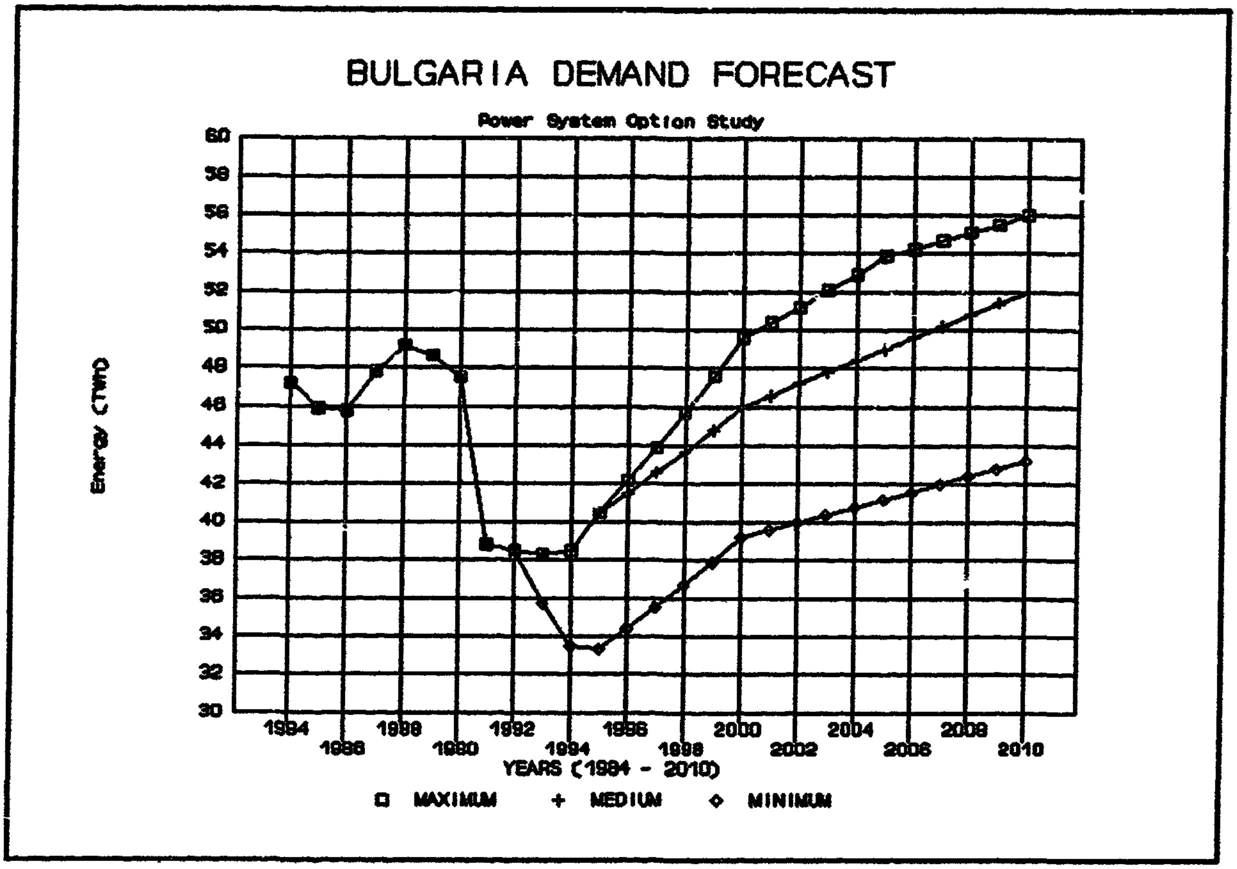
1.03 Demand. Electricity consumption in Bulgaria is very high relative to the size of its economy. Electricity intensity in 1990, for example was about 2.1 kWh/dollar of GNP and rose in 1991. (The OECD average is 0.371 kWh/USD of GNP). This difference reflects structural and efficiency differences and is a result of:

- energy intensive industries;
- energy inefficient processes;
- electricity use for heating;
- relatively large use of electricity compared to other energy sources.

There is, however, great potential for reducing electricity intensiveness of GNP which declines in all the demand forecasts discussed below.

1.04 Electricity demand grew 11.5% per year from 1950 to 1988, with domestic demand peaking at 49.2 TWh in that year. Domestic demand fell slightly in 1989 and then dropped by 5.7% in 1990, 10.7% in 1991 and about 7.3% in 1992. Peak demand also fell from 8,332 MW in 1989 to 7,489 MW in 1991 and about 7100 MW in 1992. Looking ahead, a number of forecasts of Bulgarian electricity consumption over the next 10 to 15 years are available. All forecasts assume that industrial restructuring continues and, therefore, the intensity of electricity consumption declines. The forecasts vary depending primarily on the assumptions they make about: (a) the speed at which industrial restructuring occurs; (b) the extent of the impact of restructuring on the intensity of electricity consumption by industry; (c) GDP growth; (d) the extent of conservation/demand side management; and (e) the extent, if any, to which households shift towards using gas for home heating rather than electricity. For the purposes of this study, three forecasts agreed with NEK and the Government (maximum, medium and minimum) were used. The medium forecast is used by the Bulgarian Government for its planning purposes, while the low forecast is similar to that used by the Bank in its Energy Strategy Study (Report 10143). These forecasts cover the likely range of possible results with two possible exceptions, involving increased conversions of households to gas fired space heating and enhanced demand side management, which are discussed in paragraphs 3.07 to 3.15 below. The three forecasts are shown in the Figure below, and all assume that the economy stabilizes between 1993 and 1995 and then begins a slow recovery. The forecasts include not only estimates of electricity consumption, but also estimates of peak demand for power.

Chart 1.1



1.05 The high forecast assumes the highest economic growth and the least adjustment by industry to the anticipated higher prices of electricity. These two events are unlikely to occur together and this forecast is an upper limit. The low case forecast is just the reverse and assumes lower economic growth and more adjustment by industry. It also assumes the maximum impact of demand side management considered to be economically and institutionally feasible. Finally, it assumes that 450,000 household convert from electric heating to natural gas after the year 2000 while the high scenario assumes no conversions. The medium forecast falls in between the high and low forecasts and assumes no major conversions of households to gas, moderate economic growth and a more gradual adjustment by industry to higher energy prices. The latter forecast is viewed as the base forecast for planning purposes, since it is conservative in the sense that demand is likely to be at that level or below.

1.06 Capacity. Bulgaria's total installed generating capacity increased from 8,810 MW in 1980 to 12,074 MW in 1991, with almost all of the new capacity that was added to the system being in the form of nuclear. This simply reflects the continuation of the Government's policy of expanding nuclear generating capacity, which was adopted in the 1970s, as a means for offsetting the constraints arising from the country's limited endowment of commercial energy resources. The first nuclear reactor at Kozloduy (unit 1), a Soviet designed and built VVER 440, model 230, with a capacity of 440 MW was commissioned in 1974. Over the next 16 years, another 3,320 MW were added to the plant at Kozloduy, comprising 3x440 MW (VVER 440, model 230s, units 2-4) and 2x1000 MW (VVER-1000s, units 5-6).

The last unit of 1000 MW, unit 6, was brought on stream in 1991 and is in the process of being commissioned. As a result, the share of nuclear in total installed capacity has more than doubled, from 15% in 1980 to 31% in 1991, while that of thermal and hydro has declined correspondingly: from 64% to 53% for the former and from 21% to 16% for the latter, respectively. Details relating to the growth in capacity are presented in the table below.

Table 1.2

Developments in the Growth of Installed Capacity and Generation
(MW and GWh)

	1980	1985	1988	1990	1991
Hydro					
Capacity	1,868	1,975	1,975	1,975	1,970
Generation	3,713	2,236	2,596	1,851	2,441
Thermal					
Capacity	5,622	6,508	6,574	6,400	6,344
Generation	24,955	26,265	26,395	25,614	23,209
Nuclear					
Capacity	1,320	1,760	2,760	2,760	3,760
Generation	6,165	13,131	16,030	14,665	13,184
TOTAL					
Capacity	8,810	10,243	11,309	11,135	12,074
Generation	34,833	41,632	45,021	42,130	38,834

1.07 Scenarios. As agreed with the Bulgarian authorities, six nuclear scenarios have been considered, and these are given immediately below. Mostly, these scenarios involve the dates at which some or all of the VVER 440s at Kozloduy (units 1 to 4) are retired, since these units are considered "unsafe" by most experts in their current condition. Each scenario, therefore, involves a different availability of nuclear power. A system analysis was then carried out with the requirement that future demand for electricity and peaking capacity should be met at the least cost given the availability of nuclear power shown for that particular scenario. The scenarios are:

Scenario 0 - All six units at Kozloduy cease power production immediately*, no further nuclear development.

Scenario 1 - Kozloduy units 1 to 4 cease production immediately*, Kozloduy units 5 and 6 continue production to end of design life.

Scenario 2 - Kozloduy units 1 and 2 cease power production immediately*, units 3 and 4 cease power production 1/1/98, units 5 and 6 continue operation to end of design life.

Scenario 3 - Kozloduy units 1 to 4 cease power production 1/1/98, units 5 and 6 continue operation to end of design life.

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* For purposes of analysis, immediately is taken as 1993. The relative results would be unchanged if 1994 were used instead.

Scenario 4 - Kozloduy units 1 and 2 cease power production 1/1/98, units 3 to 6 continue operation to end of design life.

Scenario 5 - All six units continue operation to end of design life. (2005 for units 1, 2006 for unit 2, 2011 for units 3 and 4 and about 2019 for units 5 and 6).

For the purpose of comparing this report with those prepared for other countries, scenario 1 will be taken as the "low nuclear" scenario, scenario 3 as the "moderate nuclear" scenario, and scenario 4 as the "high nuclear" scenario. In all these scenarios, no investment in new nuclear units would be considered. However, an additional scenario was considered at the request of the Bulgarian authorities and that was Scenario 6 - All six units continue operation through to the end of their design life, and additional nuclear units would be considered as candidates for new plants. In fact, that turned out to be the same scenario as scenario 5, since new nuclear plants were not a least-cost solution.

1.08 In all the scenarios, if nuclear units are to continue to operate for an extended period, the cost of safety upgrades for those units are included in the cost of supplying electricity under that scenario. (This is not the current situation where the required safety upgrades have not yet been undertaken.) The cost of these safety upgrades has been provided by the Bulgarian authorities based on the work of outside consultants and are shown in Table 5.1. They range from an average of US$87 million/year (1993 dollars) in scenario 5 to very little in scenario 0, where the nuclear units cease production immediately.

1.09 Eighteen different cases were considered, consisting of one of the six nuclear supply scenarios combined with one of the three demand forecasts. In order to meet demand for electricity in each case, a number of alternative sources of electricity were considered with the least cost alternative chosen. These alternatives include: (a) rehabilitation of existing thermal power plants (4730 MW), which mainly burn coal or lignite; (b) rehabilitation/repowering of existing cogenerating plants (district heating plants and industrial plants totalling about 1614 MW), which mainly burn imported natural gas; and (c) new plants including gas turbines, gas fired combined cycle plants, plants fired with imported coal etc. Also, some consideration was given to two non-electric alternatives: (1) replacing electricity, a significant part of which is used by consumers to produce heat, with natural gas for heating purposes; and (2) replacing electricity with various demand side management techniques, in addition to those already taken into account. These non-electric alternatives are quite intriguing (see paras 3.07 to 3.15), but insufficient information is currently available in Bulgaria to be sure that they are economically or institutionally feasible.

Results

1.10 The total system costs (fuel, operations, maintenance, investments) of supplying electricity at the lowest possible cost for the 18 cases have been estimated to the year 2010. Total system costs clearly indicate three groups of scenarios: (a) group A (scenario 0), (b) group B (scenarios 1, 2 and 3), and (c) group C (scenarios 4 and 5).

Group A - Scenario 0 (immediate closure of all nuclear plants) is a substantially more expensive solution than any other. In addition to that, the system parameters given in the main report indicated that this is not a feasible solution, since it would result in numerous prolonged outages.

Group B - Scenarios 1, 2 and 3 which assume Kozloduy units 1-4 cease generation in 1993 to 1998 are very similar from the point of view of total costs. The difference between the lowest and highest values for different load forecasts is within 5 to 7%.

<u>Group C</u> - Scenarios 4 and 5 show practically no difference and are lower cost than the scenarios in Group A or B.

1.11 This analysis of the Bulgarian electricity system shows that aside from scenario 0, which involves shutting all 6 units at Kozloduy and is infeasible, the other five scenarios which involve closing units 1-4 at various dates or keeping all units running through the end of their design life are potentially feasible though with different costs. The longer units 1-4 are run, the lower are the total costs of supplying electricity with scenario 5, which involves running all units to the end of their design life after safety upgrades, being the lowest cost of all. In choosing between scenarios 1-5, the Bulgarian authorities must primarily consider three factors: 1) nuclear safety; 2) costs (both local and foreign); and 3) the availability of non-nuclear fuels (most of which are imported) especially natural gas for which there is a single supplier. The choice between scenarios is largely a matter of trade offs. Increasing nuclear safety above the levels which would be attained by the assumed safety upgrades (see para 1.08) raises costs and the risks involved in increasing dependance on imported non-nuclear fuels.

1.12 Table 1.3 below provides detailed results for three scenarios with the medium (base case) demand forecast. It shows in constant dollar terms the total cost of supplying electricity for scenario 1 or the low nuclear scenario under which units 1-4 cease production immediately; scenario 3 or the moderate nuclear scenario under which these units close in 1998; and scenario 4 the high nuclear scenario under which units 1 and 2 close in 1998 and the other 4 units continue to the end of their design lives. Costs of unserved energy or outages or excluded since they are small and similar for all three scenarios. The table shows that the high nuclear scenario is least cost; because the cost of fuel is substantially lower than in the other scenarios, more than offsetting the cost of the nuclear safety upgrades which are required for the nuclear units. The low nuclear scenario is the highest cost, because the increased cost of fossil fuels and higher non-nuclear investments in this scenario more than offset the savings from making lower investments in nuclear safety upgrades. However, the difference between the high nuclear scenario and the low nuclear scenario is around 11% or US$100 million per year spread over the 18 year time frame of the analysis.

Table 1.3: <u>Costs of System's Electricity Supply (1993-2010)</u>
(US$ millions, 1992 dollars)

Nuclear Scenario	Demand Forecast	Nuclear Safety Upgrade	Fuel	O&M	Non-nuclear Investment	Total
Low Nuclear (Scenario 1)	Medium	678	9,963	3,708	2,137	16,487
Moderate Nuclear (Scenario 3)	Medium	914	9,374	3,574	2,138	16,000
High Nuclear (Scenario 4)	Medium	1,210	8,478	3,[illegible]14	1,698	14,701

1.14 Tables 1.4 - 1.6 below provide summary information on the results according to a format which is standard for all the G-7 country studies. These tables cover only the period 1993-2000 or 1995-2000 rather than 1993-2010, which is the case for the other tables. Also, they show results only for the high, low and moderate nuclear scenarios assuming the medium demand forecast.

Table 1.4: Total Power Sector Investment requirements during the period 1993-2000
(US$ Million, Medium Demand Forecast)

High Nuclear Scenario	Moderate Nuclear Scenario	Low Nuclear Scenario	Difference between "High" and "Low" (High" minus "Low")
1,659	1,680	1,659	0

* 1992 prices, power plants only, i.e., transmission and distribution not included.

1.15 Table 1.4 above shows total investment requirements for the electricity system 1993-2000 assuming the medium or base demand forecast. It includes both nuclear safety upgrades and non-nuclear investments. The investments are very similar for all three scenarios for this time period since the higher non-nuclear investments in the moderate and low nuclear scenarios are similar in size to the higher nuclear safety upgrades required for the high nuclear scenario. Table 1.5 below provides a breakdown of investment by type of plant.

Table 1.5: Total Investment Requirements by Type of Plant 1993-2000
(US$ Million, Medium Demand Forecast, 1992 dollars)

1993 to 2000					
	Nuclear Upgrade		Thermal/Hydro		Total
	230's	1000's	Plant Rehab.	New Plant	
High Nuclear Scenario	325	423	521	390	1,659
Moderate Nuclear Scenario	221	423	562	474	1,680
Low Nuclear Scenario	0	423	620	616	1,659

1.16 Table 1.6 shows fossil fuel requirements in constant 1992 dollars for the three scenarios with the medium or base demand forecast. As would be expected fossil fuel requirements rise with reduced use of nuclear fuel.

Table 1.6: Average Annual Fossil Fuel Requirements during the period 1995-2000
(US$ Million, Medium Demand Forecast, 1992 dollars)

High Nuclear	Moderate Nuclear	Low Nuclear	Difference between "High" and "Low" (High" minus "Low")
2,543	2,776	3,120	577

Low Cogeneration Rehabilitation/Repowering Case

1.17 The main concern of the Bulgarian Government with the above analysis is that on average, the least cost alternative to nuclear power in Bulgaria is the use of gas fired combined cycle generating units. These units are especially economic if existing gas fired generating capacity in district heating plants and industrial plants can be converted to combined cycle, with a resultant large increase in efficiency and capacity. The Government of Bulgaria was concerned that this conversion would cost substantially more than estimated by the Bank and even more concerned about the resultant increased reliance of Bulgaria on imported gas. Currently, the country has only one gas supplier, Russia, and the pipeline has to cross three intervening countries (Ukraine, Moldova and Romania) before getting to Bulgaria. As a result of this situation, the supply of gas has become substantially less reliable with cutbacks last winter as a result of a dispute between Ukraine and Russia over transit fees. The Bulgarian Government requested that the Bank analyze the cost of electricity supplies, if gas imports for power and district heating were limited to 2 billion cubic meters per year (roughly current levels) and the new additional gas fired generating capacity is limited to 500 MW. This was done and is shown in Table 1.7 below for the medium demand case and three scenarios. It increases the costs of supplying power by around 3-8%, depending on the scenario and demand assumptions. Also, it would change the pattern of expenditures by requiring higher total outlays in the earlier years (for coal/lignite fired units), but somewhat lower fuel costs in the longer term, since coal and lignite are assumed to be cheaper than natural gas. This limitation on gas usage may also not be relevant, if the current active exploration program in Bulgaria by international oil companies finds significant quantities of gas.

Table 1.7: Costs of System's Electricity Supply with Limits on Gas Usage 1993-2010
(US$ millions, 1992 dollars)

Nuclear Scenario	Demand Forecast	Nuclear Safety Upgrade	Fuel	O&M	Non-nuclear Investment	Total
Low Nuclear (Scenario 1)	Medium	678	9,264	3,924	3,392	17,259
Moderate Nuclear (Scenario 3)	Medium	914	8,649	3,705	3,389	16,659
High Nuclear (Scenario 4)	Medium	1,210	8,025	3,412	2,411	15,059

1.18 This study represents an initial effort to quantify the costs of replacing nuclear power in Bulgaria with alternative energy sources and the more efficient use of energy. It is based on all the information available at this time (April 1993). However, a number of studies are underway which will provide additional information and should enhance the analysis. These studies include, but are not limited to: the studies of Bulgaria's major thermal power plans and district heating plants financed by USTDA; the study of Bulgaria's generation financed by the CEC; the Energy Efficiency studies financed by USAID (industry) and the Danish Government (households/district heating); and the nuclear upgrade studies financed by the CEC and USTDA.

II. ENERGY SECTOR OVERVIEW

A. Background

2.01 Energy Resources. Bulgaria's endowment of commercial energy resources is extremely poor. The very limited initial reserves of oil and gas have declined steadily and are now estimated at about 3 million tonnes of oil equivalent, representing less than 3 months of the country's petroleum consumption. The hydropower potential is also limited as most of Bulgaria's rivers are small, except for the Danube which, however, has a fairly small drop in altitude where it forms the country's northern border with Romania. Largely because of this constraint, hydro capacity accounts for about 16% of the country's total installed generating capacity and an even smaller percentage of generation. The reserves of the presently active coal mining areas are estimated at about 2.6 billion tonnes, with lignite accounting for about 90% of these reserves and sub-bituminous and bituminous coal for the remaining 10%. The latter are spread thinly across the country, which often renders their extraction uneconomic. As for the lignite reserves, over 95% of these are located in the southeast of the country, at Maritza East, and are sufficient to meet the requirements of the existing three mine-mouth power plants and the briquette factory for another 75 years. Because of the moderately favorable mining conditions, which are characterized by an easily accessible terrain, a thick lignite seam and the absence of groundwater problems, the reserves at Maritza East are likely to remain the country's principal economically exploitable energy resource in the medium to long term. However, as the lignite is of poor quality (heating value of about 1,500 kcal/kg, a sulfur content of about 2%), and cannot be transported economically over long distances, it would continue to be the main source of primary energy for the generation of electricity at pit-head power plants and for the production of steam for industries located in the vicinity of the mines, as has been the case thus far.

B. Sector Organization

2.02 The main sector operating organizations are the National Electric Company (NEK), Neftochim, Petrol, Toplivo, the Maritza East Mines, Bulgargaz, the Sofia Energy Combine and the Oil and Gas Exploration and Production Company. NEK is the state power company producing about 80% of the electricity consumed in Bulgaria. Neftochim is the primary state refining company operating the large refinery at Burgas. Petrol is the monopoly petroleum product distributor and gasoline marketing organization while Toplivo, which has activities outside the energy sector, markets coal, propane/butane and briquettes to the household sector. The three Maritza East Mines are the by the far the largest and most profitable coal mines in Bulgaria producing 75% of the country's coal output from the large Maritza East deposit. Bulgargaz is the state gas transmission company while the Sofia Energy Combine is by far the largest district heating system in Bulgaria and supplies 75% of the population of Sofia with heat. Finally, the Oil and Gas Exploration and Production Company is the sole Bulgarian oil and gas producing company, though it produces very little of either commodity. Some of the above operating organizations report to ministries others report to Committees which in turn report directly to the Council of Ministers (COM). There is no Ministry of Energy nor any central organization coordinating activities in the sector or providing oversight for the sector as a whole.

2.03 Rather, there are several different organizations responsible for different parts of the sector. The Ministry of Industry has responsibility for: (a) gas transmission (Bulgargaz); (b) refining (Neftochim, two very small refineries); (c) petroleum distribution and transport fuels marketing (Petrol); and (d) marketing of household fuels (Toplivo). The Committee of Energy (COE) has oversight and policy responsibility for the electricity subsector, coal mining and district heating. It is entirely independent of any ministry and reports directly to the COM. The Committee of Geology and Mineral Resources (COMGEO), which has policy and oversight responsibility for oil and gas exploration and production and minerals exploration, is also independent and reports to the COM. The only organization which appears to be responsible for the sector as a whole is the so called "Commission to the Council of Ministers on Energy and Raw Material Supplies for the Country". This is basically a standing committee of the COM and is composed of representatives of various ministries and energy organizations. It has no staff and meets only as required for dealing with immediate crises. It is not designed to and cannot provide longer term policy, coordination or oversight for the sector.

2.04 The creation of a national energy agency in Bulgaria has been proposed, which would have responsibility for the various energy sector organizations. The initial component of this proposed agency would be the staff of the COE. In addition, the units of the Ministry of Industry which deal with energy issues would be incorporated into the new agency. In the Energy Strategy Study (ESS) (Report No. 10143), it was recommended that in addition to these two components, COMGEO, and the Commission on Prices be incorporated into the new agency. The Commission on Prices (COP), a governmental group charged with overseeing prices and regulating energy monopolies, could then form the basis for creating a utility regulatory authority, which would be independent, but connected to this energy agency. The energy agency would have oversight responsibility for all energy sector organizations which were not yet privatized. However, these organizations would operate as commercial entities in the emerging market economy with largely autonomous boards of directors appointed by the government. After privatization all energy sector organizations should be independent and private utilities would be regulated by the new regulatory authority.

2.05 Under the regime, which existed in Bulgaria until the end of 1989, decision making was centralized largely in Sofia. Top operating management was given limited authority and even less incentive to improve performance. Over the past two years, the top management of most energy sector organizations has been given increased responsibility though this should be further expanded. The government is in the process of developing performance contracts for upper level management, which are very much needed, and should help provide incentives. In addition, however, within energy sector organizations responsibility and authority has to be delegated downwards to a greater extent. Plant managers must have authority to take the actions needed for safety and the proper operation of their plants. This process is underway, but still has some way to go.

C. Pricing of Energy

2.06 The energy sector is the only sector currently where prices are generally still controlled. The degree of control, however, varies greatly within the sector. The prices of electricity, coal and heat are set by the COM. The prices of petroleum products on the other hand are partially liberalized with a ceiling price determined by world product prices. Finally, natural gas prices in 1991 were set based on the costs of Russian gas imports but this mechanism was change in early 1992 and they are now tied to the price of heavy fuel oil.

2.07 Electricity. The COM sets electricity, heat and coal prices based on a recommendations from the Commission on Prices and COE. The COM, however, is not bound to accept the recommendations of the Commission on Prices or COE and instead has fixed these prices, which are quite politically sensitive, based on a mixture of economic and political considerations. Nevertheless, the COM has increased electricity prices very sharply since July 1990, first in February 1991 and again in June 1991, May 1992 and January 1993. As of January 1993, average industrial electricity prices were fifteen times the level in July 1990, while average household electricity prices were ten times their 1990 level (see Table 2.1). While the COM fixes the average electricity price, the Commission on Prices and the COE together work on the structure of the tariffs used for electricity which will produce the average price. For industry a three part tariff is used with three different charges (peak, day, night) depending on the time of day. For households a two part tariff is used for most households (day, night) with a single tariff, used for those households which do not have time of day meters. The current average price for industrial users is .79 lev/kWh (3.2 cents/kWh) and for households it is .40 lev/kWh (1.6 cents/kWh) with an average price for all users of about .64 lev/kWh (2.5 cents/kWh).

2.08 NEK's income statement and balance sheet are still somewhat distorted by the radical changes in prices and exchange rates which have occurred. While the data do not exist to make all of the required corrections it is likely that the actual average cost of electricity at the beginning of 1993 was around 3.0 cents/kWh and possibly higher. The average long run marginal cost of electricity is probably similar though somewhat higher. It should not be as high as in most market economies since new capacity may not be needed for some years. This means that electricity prices for both industry and households are almost certainly below average long run marginal cost and should be increased. [Such an increase is a requirement under the Bank's Energy Loan to Bulgaria, see the Staff Appraisal Report (SAR)[1]]. It also means that electricity prices for households are much further below average long run marginal cost and for this reason would need to be increased more than the prices for industry.

2.09 Not only are current electric prices generally too low, but the current tariff structure creates a distortion. Prices for electricity supplied to industry should be generally less than prices for households (rather than more as in Bulgaria), because it is generally less expensive to supply industries. There are a number of reasons for this which include: (a) significant economies of scale in supplying large quantities of electricity to a single location which arise from the use of high voltage lines with lower transmission losses; (b) an improved load factor; (c) lower coincidence with the system peak. This distortion in the Bulgarian tariff structure, created by pricing electricity to industry higher than to households grew worse from 1990-1992, but the government is currently trying to correct it.

2.10 District Heat. District heating plants supply about 22% of Bulgaria's household consumption of heat (mostly hot water), and about 58% of Bulgarian industries' heat requirements (hot water and steam). These heating plants primarily produce steam and hot water, but some are also CHP units, producing power. Some of the largest industrial plants which use the steam have heat meters to measure what they receive but many of the smaller plants do not. Moreover, households do not have heat meters and are billed for their heat on the basis of the cubic meters of space in their apartments or houses. The price of district heat, which is set by the COM, has increased very sharply, but is still on average far below cost.

2.11 Coal. The COM sets a reference price for Bulgarian coal, based in part on recommendations from the Commission on Prices and COE. This reference price is for a good quality coal with a heating value of 7000 kcal/kg. Bulgarian coals, however, are of much poorer quality than the reference coal and so their actual prices are set relative to the reference coal by the COE, with the agreement of the Commission on Prices. For example, the heating value of Bulgarian coals ranges from 1,200 kcal/kg. to 5,500 kcal/kg, and so the prices of these Bulgarian coals have to be set relative to their heating value as well as taking into account other factors such as moisture, ash etc. Altogether there are around 400 different prices for coal. The prices of imported coals are not controlled except for the very small amount sold on the retail market, which have the same price control arrangements as for Bulgarian produced coals. Coal reference prices were increased sharply in February and June of 1991 and May 1992 (see Table 2.1). The current reference prices for Bulgarian coal are 606 Lv/T (US$1.03/GJ) for sale to industry and 406 Lv/T (US$0.69/GJ) for sale to households. Industrial companies are expected to pay transport to their plants for the coal they use. The great bulk of Bulgarian coal is used for power generation by NEK which pays the industrial price. Nevertheless, this price is below the cost of producing coal which on average in Bulgaria is currently about US$1.80/GJ. However, this cost is raised sharply by the fairly large number of currently uneconomic mines which exist in the country. The main mining complex in the country which produces about 75% of output (by weight), Maritza East, has a cost of about US$1.0/GJ. Thus, the industrial price of coal, though low, is not as far below costs as it might first appear.

1/Report 11250.

2.12 Petroleum. For the more important petroleum products, ceiling prices for final sales are determined monthly based on a formula devised by the Commission on Prices. This formula relates local Bulgarian retail product prices to world market prices with a one month lag. The formula has built into it estimates of freight, insurance and the dollar/leva exchange rate and also provides for import duties and excise taxes. The formula also has a built in margin designed to cover distribution costs, selling costs (if any) and provide a small profit. Sellers are still free to sell at less than the ceiling price established by this formula, but since petroleum sales are still a state monopoly there is no incentive to do so. The prices produced by this formula exceed cost. Also, these petroleum product prices, especially gasoline, are relatively low by world standards since the Bulgarian excise tax is low. As gasoline service stations are privatized (under the government's economic reform program) and free imports of petroleum products are allowed, price controls on petroleum products should be removed. The present price control formula should be an interim step in the process of freeing petroleum product prices.

2.13 Natural gas. Natural gas prices in 1991 were not controlled directly by the government, though they were subject to oversight by the Commission on Prices. Gas prices were set by Bulgargaz, the state gas transmission company, and consisted of the price that Bulgargaz paid the Russians for gas plus a small margin to cover Bulgargaz's costs and the fee paid the Romanians for moving the Russian gas across Romanian territory. However, these gas prices expressed in leva changed drastically over the course of 1991 due to: (a) the indexation of Russian gas prices (which are denominated in dollars) to world petroleum product prices, which fluctuated unusually widely as a result of the Gulf War; and (b) changes in the leva dollar exchange rate in part emerging from bilateral trading considerations. As a result of these fluctuations in gas prices the government at the beginning of 1992 decided to set the sales price of natural gas by Bulgargaz based on the price of heavy fuel oil on a heating value basis. The price of heavy fuel oil in Bulgaria is in turn determined by the petroleum product pricing formula discussed above. While it is understandable that the Bulgarian authorities were concerned about the fluctuations in the leva price of natural gas, nevertheless, the sales price in Bulgaria for this gas should be based on its costs not a hypothetical relation to heavy fuel oil prices though the gas price resulting from the formula is fairly close to the cost of gas.

Table 2.1

Selected Bulgaria Energy Prices
July 1990 - January 1993
(in leva/unit)

	1990 July	1991 February	1991 June	1992 May	1993 January
Electricity (1000 kWh)					
Industrial Use	52	271	461	756	790
Household Use	38	167	284	324	402
Heating (1000 kcal)					
Industrial Use	18	165	281	334	370
Household Use	10	50	85	115	149
Brown Coal (Tonne)					
Industrial Use	20	285	485	606	606
Household Use	28	210	375	506	506

D. Energy Consumption

2.14 Bulgaria has historically followed a very energy intensive development policy. The emphasis has been on development of heavy industries with the energy for these industries largely imported at favorable prices from the Soviet Union. This policy had three results which increased energy intensity. First, the share of industry in GDP in Bulgaria is higher than in most Western countries and industry tends to consume more energy per unit of output than other components of GDP such as services. Second, Bulgaria has a higher share of energy intensive industries such as organic and inorganic chemicals in total industrial output. Third, the technology used in Bulgarian industry is generally much less energy efficient than the technology now used in the West. As a result, the energy intensiveness of Bulgaria's GNP (energy consumption per unit of GNP) is significantly higher than for a comparable market economy. Furthermore, the electricity intensiveness of Bulgaria's GDP is relatively much higher than its energy intensiveness (several times the OECD average) because the country uses electricity heavily, especially for heating.

2.15 As a result of Bulgaria's energy intensive economy and very limited domestic energy resources, most energy has to be imported. These energy imports consist of over 99% of the oil and gas used by the economy, about 30% of the coal consumed on a heating value basis, 8% of the electricity and 100% of the nuclear fuel. Using the normal convention which treats nuclear power as a domestic energy resource no matter what the source of the nuclear fuel, Bulgaria imports about 66% of its energy supplies (see Table 2.2). If, however, domestically generated nuclear power were to be considered as an import because the fuel is imported then about 80% of the country's energy supplies are imported with the remaining 20% being locally produced, from lignite and a limited amount of hydro capacity. Either one of these figures is a high level of import dependency, especially for an economy which is so energy intensive. Most of these energy imports (85-90%) are from the former Soviet Union (FSU) primarily from the Ukraine and Russian Republics. As a result of this combination of energy intensity and import dependence, Bulgaria's energy imports are a relatively large share of its total imports amounting to 23% in 1990 (US$1.9 billion equivalent), with insignificant exports of energy.

2.16 So far, the energy intensity of Bulgarian GDP does not appear to have decreased, with energy consumption and output falling at roughly the same rate. However, this pattern should start to change as the economic restructuring occurs and as relative energy prices continue to increase. Reduction of energy consumption and, therefore, of net energy imports is likely to be an important component of any improvement of Bulgaria's balance of trade.

2.17 The pattern of energy use in Bulgaria is significantly different from the West. The main area of difference is in the direct use of gas. In most western industrial countries gas is used in industry, in power generation and by households and the service sector. In Bulgaria, it is almost entirely used in the industrial sector and in power generation including district heating plants (many of the latter being combined heat and power (CHP) plants) with a negligible amount being used in services and households (see Table 2.2). Furthermore, this lopsided pattern of usage will not change rapidly since Bulgaria lacks a distribution network for gas so that it cannot currently be supplied to most households and commercial establishments. Indirectly, of course, the household and service sectors use some gas since a small part of the electricity they consume and most of the heat supplied by district heating plants, comes from gas. Even taking this indirect use into account, however, the use of natural gas in Bulgaria is still heavily skewed towards the industrial sector.

2.18 Looking ahead, energy consumption is expected to decline for the next two to three years and then to increase slowly. The extent to which it declines and pace at which it recovers depends on a number of factors, the most important of which are: (a) growth of GDP; (b) energy prices; (c) the extent and speed of industrial restructuring (shifting from heavy industries towards services etc.); and (d) the speed at which energy efficient technologies will be introduced. However, almost all forecasts call for energy demand to grow more slowly than GDP and for a shift in the pattern of fuel use, from coal towards greater use of natural gas and petroleum.

BULGARIA: ENERGY BALANCE 1991
estimates in thousands of tonnes of coal equivalent

	Coal	Crude Oil	LPG	Light Prod.	Heavy Prod.	Other Prod.	Natural Gas	Nuclear	Hydro	Electricity	Heat	Total
Production of pr. energy	6,997	81					12	4,708	872			9,008
Net Imports	4,085	6,419		358	2,330		6,394			255		19,841
Changes in stocks	62	-101	4	393	92		164					614
Total Input	11,144	6,399	4	751	2,423		6,570	4,708	872	255		33,123
Conversions - Total	-8,710	-6,397	321	1,732	664	114	-3,635	-4,708	-872	4,781	6,269	-10,440
Briquette plants	-56											-56
Coke plants	-118											-118
Petroleum refineries		-6,397	357	1,926	3,898	114						-139
Public power plants	-5,861				-61		-453	-4,708	-872	3,913		-8042
Power plants CGEEH	-1,565			-3	-367		-1358			422	1,639	-1,233
Autoproducers of Electr.	-920		-36		-723		-1,462			446	2,128	-566
Heating plants	-190			-191	-2,083		-363				2,502	-323
Own Use & Distribution			-2				-48			-1,173	-304	-1,527
Non-energy use			-248	-696	-118	-114	-476					-1,653
Total Supply	2,433	2	75	1,787	2,969	0	2,411	0	0	3,863	5,964	19,504
Final Consumption - Total	2,433	2	75	1,787	2,969	0	2,411	0	0	3,863	5,964	19,504
Mfg., mining & const. total	904		30	183	606		2,315			2,083	4,579	10,701
Iron and steel	598			1	12		214			285	146	1,256
Non-ferrous metals	61		1	8	128		10			189	71	467
Chemical industries	212	2	1	34	15		1,362			555	1,844	4,025
Other industries	34		28	141	450		729			1,055	2,518	4,953
Transport Total	12			369	1,009					127	22	1,538
Other Total	1,298		44	1,235	1,392		91			1,654	1,364	7,079
Households	1,181		44	728	164					1,278	908	4,304
Agriculture, forestry	50			186	760		25			106	214	1,342
Trade	16			102	45		4			77	42	286
Other consumers	51			219	423		62			192	200	1,147
Not specified	219		1	-1	-38	0	5	0	0	0	0	186

Source: NEK, COE. Hydro and nuclear electricity converted to heat at 2,500 kcla/kWh.

Table 2.2

III. ELECTRICITY DEMAND

A. Overview

3.01 Bulgaria has also followed a very energy and electricity intensive development policy. The emphasis has been on the development of heavy energy/electricity intensive industries which used electricity inefficiently and virtually all households in Bulgaria are attached to the national grid with electricity widely used for heating. This electricity intensive development process, with electricity usage growing 11.5% per year from 1950 to 1988, was also encouraged by very low prices for electricity through out this period. As a result of these factors, the electricity intensity of Bulgaria's GDP is quite high with Bulgaria using over five-times the electricity per unit of GDP of comparable market economies.

B. Recent Development

3.02 Table 3.1 shows the decline in Bulgarian electricity consumption over the past several years. Gross domestic consumption of electricity (excluding exports but including all losses) has dropped from an all time peak of 49.2 TWh in 1988 to 41.0 TWh in 1991 and it declined further to about 38 TWh in 1992. This decline is less, however, than the decline in GDP over this same time period. For example, the decline in electricity consumption from 1988 to 1991 is 16.7% while the decline in real GDP over this same time period is 22.4%. Using preliminary estimates for 1992 electricity consumption and GDP, the total decline in electricity consumption relative to 1988 would be 23% while the decline in real GDP, again relative to 1988, would be 28.4%.

Table 3.1: Electricity Demand and Supply (TWh)

	1988	1989	1990	1991
Sources of Electricity				
Electricity Generation	45.04	44.33	42.13	38.92
Imports	4.45	4.93	5.39	3.72
Total Sources	49.49	49.26	47.52	42.64
Uses of Electricity				
Industry	21.15	20.77	19.38	14.92
of which:				
Ferrous Metallurgy	3.03	2.98	2.92	2.32
Non-Ferrous Metals & Non-Metallic Minerals	1.91	1.86	1.78	1.54
Machine Building	2.03	2.21	2.11	1.50
Refining/Chemicals	6.37	5.96	5.35	4.52
Building Materials	1.40	1.31	1.16	0.95
Food	1.45	1.52	1.31	1.05
Other Industry	4.96	4.93	4.75	3.04
Construction	1.14	0.99	0.90	0.61
Agriculture	1.10	1.07	0.99	0.87
Transport	1.32	1.32	1.30	1.21
Residential Consumption	9.94	10.18	10.47	10.40
Exports	0.30	0.55	1.60	1.64
Transmission & Distribution Losses	4.79	4.66	4.44	5.23
Street Lighting	0.36	0.40	0.38	0.32
Use by power plants	4.90	4.84	4.62	4.21
Other	4.49	4.48	3.44	3.21
Total Uses	49.49	49.26	47.52	42.64

3.03 Table 3.1 also shows the reasons why electricity consumption is not declining as rapidly as GDP. While industrial consumption of electricity is generally dropping at the same rate as GDP, other categories of electricity consumption are not. In particular, household consumption of electricity has actually risen since 1988. This increase in household consumption is primarily the result of more households using electricity for heating as the prices of petroleum products used for heating (home heating oil, propane/butane) have increased. In addition, transmission and distribution losses, which are counted as part of domestic consumption, have also increased largely as a result of the rising theft of electricity. Finally, other categories of electricity consumption such as street lighting, transport and agricultural uses have not declined very much.

C. Forecasts of Electricity Consumption

Table 3.2: Forecast of the Electricity Demand and the Peak Loads for Bulgaria

Years	Maximum		Medium		Minimum	
	TWh	MW	TWh	MW	TWh	MW
1993	38.3	6840	38.3	6840	35.7	6370
1994	38.5	6870	38.5	6870	33.5	6050
1995	40.5	7230	40.5	7230	33.3	5950
1996	42.2	7540	41.5	7410	34.4	6140
1997	43.9	7840	42.6	7610	35.5	6340
1998	45.7	8160	43.7	7800	36.7	6550
1999	47.6	8500	44.8	8000	37.9	6770
2000	49.6	8700	46.0	8070	39.2	6880
2001	50.4	8840	46.6	8180	39.6	6950
2002	51.2	8980	47.2	8280	40.0	7020
2003	52.1	9140	47.8	8390	40.4	7090
2004	52.9	9280	48.4	6490	40.8	7160
2005	53.9	9440	49.0	8600	41.2	7230
2006	54.2	9510	49.6	8700	41.6	7300
2007	54.7	9600	50.2	8810	42.0	7370
2008	55.1	9670	50.8	8910	42.4	7440
2009	55.5	9740	51.4	9020	42.8	7510
2010	56.0	9820	52.0	9120	43.2	7580

3.04 A number of forecasts of Bulgarian electricity consumption over the next 10 to 15 years are available. All forecasts assume that industrial restructuring occurs, the intensity of electricity consumption in industry declines and that output of services and agriculture grow faster than industry. The forecasts vary depending primarily on the assumptions they make about: (a) the speed at which industrial restructuring occurs; (b) the extent of the impact of restructuring on the intensity of electricity consumption by industry; (c) GDP growth; (d) electricity conservation/demand side management; and (e) the extent, if any, to which households shift towards using gas for home heating rather than electricity. For the purposes of this study, three forecasts agreed with NEK and the COE (maximum, medium and minimum) were used. The medium forecast is preferred by the Bulgarians for planning purposes, while the minimum forecast is very similar to that used by the Bank in the ESS. The maximum forecast is an upper bound. These forecasts cover the likely range of possible results with two exceptions which are discussed in paragraphs 3.07-3.11 and 3.14-3.15 below. The three forecasts are shown in Table 3.2 and all assume that the economy stabilizes between 1993 and 1995 and then begins a slow recovery. The forecasts also include not only projections of electricity consumption in TWh, but also projections of peak demand for power in megawatts (MW).

3.05 The high forecast assumes the highest economic growth and the least adjustment by industry to the anticipated higher prices of electricity. The low forecast is just the reverse and assumes lower economic growth and more adjustment by industry. It also assumes that 450,000 households convert from electric heating to natural gas after the year 2000 while the high forecasts assumes no conversions. The medium forecast falls in between the high and low forecasts and assumes no major conversions of households to gas, modest economic growth and a more gradual adjustment by industry to higher energy prices.

D. Load Management

3.06 It is useful to distinguish between two different concepts in load management: (a) demand management, and (b) supply management. Demand management refers to techniques which impact directly on the energy consumption patterns of individual consumers (e.g. direct control, voluntary control, customer energy storage); supply management refers to the use of utility-owned facilities to improve the manner in which electric energy is provided to the final consumer (e.g., utility storage and expanded interconnection).

D.1: Demand Side Management

3.07 Demand reduction. The low electricity demand forecast assumes rapid adjustment by industry, and to a lesser extent other sectors, to higher electricity prices; and a moderate demand side management effort corresponding to the limited institutional capacity in this area and low electricity costs. An active government program over five to ten years might be able to reduce demand below the low scenario thus supplementing the impact of restructuring and higher prices. Some of this additional saving would occur in the industrial sector but much of it would probably be in the household and communal sectors (public buildings, shops).

3.08 In the industrial sector energy audits performed by consultants to USAID show short term savings potential for electricity, involving little or no capital investments, of about 12%. The longer term savings potential is estimated at around 35% which would, however, involve new capital investments, though the latter would be highly economic. A substantial part of these potential savings will occur as a result of industrial restructuring, but the savings could be somewhat accelerated by Government assistance.

3.09 The potential for savings in the household and communal sector is even larger especially with respect to heating. Data for 1988 reported by a Danish-Bulgarian study (Birch and Krogboe and the Ministry of Construction Sept 1991) indicates that the energy consumed per degree day per m^2 for Bulgaria, was about 237 kJ, while figures for the USA and Sweden are 160 and 135 kJ for the existing housing stock and the averages for new stock are 100 and 65 respectively. Best available modern technology gives around 35 kJ per m^2 per degree day. Thus the potential for savings in space heating is very large.

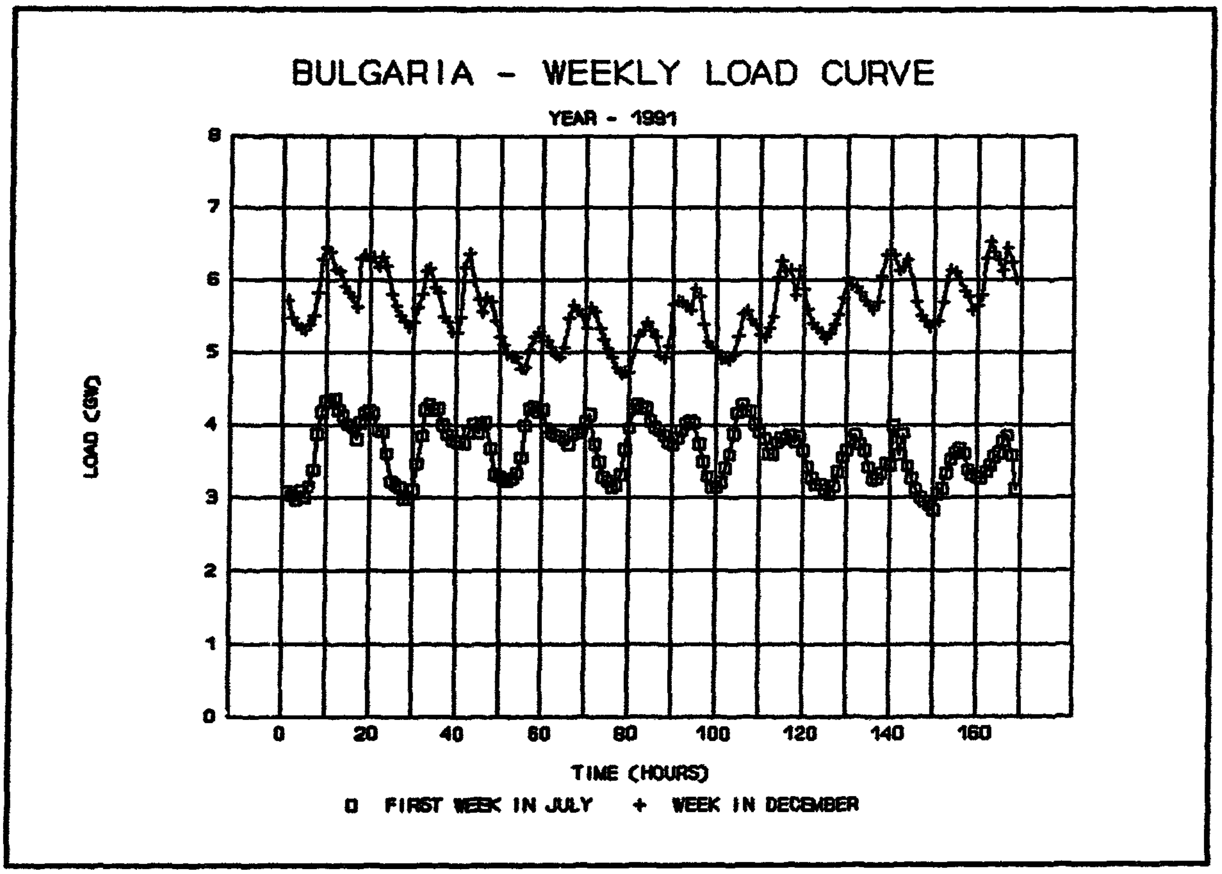
3.10 This same Danish/Bulgarian study also provided information about where some of the potential savings are located, and rough indications of the investments required and the paybacks assuming electric heating. The three main areas identified as having the highest potential for saving electric heat were improved window seals, balcony retrofits and low emission venetian blinds. For apartments, the payback period for these investments were from 1 to 4 years (assuming they heated with electricity), energy savings (part of which would be electricity) would be around 3.3 TWh equivalent and the total investment required was estimated at around US$200 million. All of the saving measures suggested by the study correspond closely to standard western European practices. In addition, Bulgaria might move beyond standard western European energy saving technology by, for example adopting more advanced technology such as the use of high efficiency (compact fluorescent) light bulbs. (These bulbs would cut electricity consumption by around 50 GWh per million light bulbs in use and last about 10 times as long as a conventional bulbs at a cost estimated at around US$80-US$85 million per million light bulbs.)

3.11 While the savings potential in the household and communal sector is large as indicated above, the achievement of these savings is likely to be slowed by: (a) lack of awareness by households and building managers of the potential for electricity savings; (b) lack of proper materials for undertaking conservation measures (insulation, window sealant); and (c) the scarcity and high cost of funds for undertaking such investments. The government needs to develop an active program to encourage energy saving in this sector. Elements of such a program might include: (i) an energy conservation office to coordinate and promote conservation (the Energy Efficiency Agency is a major first step in this direction); (ii) improving building codes; and (iii) programs to encourage small scale energy and electricity conservation investments such as having NEK make some such investment and include them in its rate base. While the impact on electricity demand of such a program cannot be estimated now, it could be significant and could reduce demand below the low forecast.

D.2 Supply Side Management

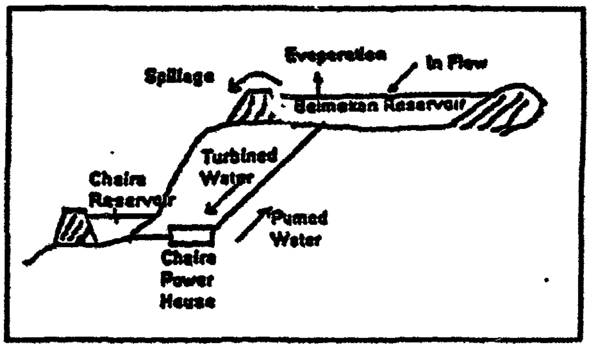
3.12 Active Load Management. The demand for electric power varies with the time of day, the day of the week, the weather, and the season. An illustration of this variation in Bulgarian system is shown in Figure 3.1 for weeks in July and December 1991. A number of methods existing for modifying these system load patterns to more closely match electric energy use with supply, and these methods fall under the general term load management, often these methods involve electricity storage.

Figure 3.1



3.13 Some of the most attra‹tive supply-side storage concepts, such as batteries and flywheels, are technologically constrained. The major supply-side storage device in commercial operation is pumped storage. The facility normally operates by pumping water into the reservoir during periods of reduced system load (e.g. nights and weekend), when the incremental cost of energy is low. During peak-load periods, water is released from the reservoir to generate electricity, thus replacing energy of higher incremental costs. However, pumped storage typically uses about 20-25% more energy than it produces. Bulgaria has a major pumped storage scheme nearly completed at Chaira, with 880 MW, and a schematic presentation of this pumped storage plant operation is given in Figure 3.2.

Figure 3.2 Chaira pumped storage operation



D.3: <u>Natural Gas</u>

3.14 In addition to load management methods for reducing electricity demand and changing the load curve, a second option exists for reducing electricity demand and that is changes in the type of energy used by final consumers. The major option would be a large program to convert households from heating with electricity to heating with gas in addition to the 450,000 household conversions already contained in the low demand forecast. The electricity savings from converting 550,000 additional households to gas by the year 2010 (bringing total conversions to 1 million households about the maximum that is considered economically feasible and covering around 30% of the population) are estimated at around 1.6 TWh. Initial rough estimates are that such a conversion would cost about US$500 per household or a total of about US$250 million. However, this number is uncertain and could be much higher if major reconstruction of apartments for new pipes has to be undertaken. The major benefit of this conversion would come not only from the reduction in electricity usage, but even more from the reduction in peak demand. It is estimated that about 2500 MW of the current peak demand is caused by household heating and that conversion of .5 million additional households to get heating might reduce the peak by as much as 900 MW.

3.15 However, the Bulgarian Government is very uncertain about the reliability of its gas supply which comes entirely from Russia with the pipeline crossing Ukraine, Moldova and Romania before it gets to Bulgaria. Given the turmoil in these countries, Bulgaria is not anxious to increase its reliance on gas until it has more than one supplier. Therefore, while large scale gas conversions are an intriguing option, this option needs considerable further study in terms both of the cost and feasibility of converting existing dwellings and also what could be done to reduce the risk associated with imported gas supplies.

IV. POWER SECTOR REVIEW

A. Introduction

4.01 Bulgaria's total installed generating capacity increased from 8,854 MW in 1980 to 12,074 MW in 1991, with almost all of the new capacity that was added to the system being in the form of nuclear. This simply reflects the continuation of the Government's policy of expanding nuclear generating capacity, which was adopted in the 1970s, as means for offsetting the constraints arising from the country's limited endowment of commercial energy resources. The first nuclear reactor (unit 1), a Soviet designed and built VVER 440, model 230, with a capacity of 440 MW was commissioned at Kozloduy in 1974. Over the next 16 years, another 3,320 MW were added to the plant at Kozloduy, comprising 3x440 MW (VVER 440, model 230s, units 2-4) and 2x1000 MW (VVER-1000s, units 5-6). The last unit of 1000 MW, unit 6, was brought on stream in 1991 and is in the process of being commissioned. As a result, the share of nuclear in total installed capacity has more than doubled, from 15% in 1980 to 31% in 1991, while that of thermal and hydro has declined correspondingly: from 64% to 53% for the former and from 21% to 16% for the latter, respectively. Details relating to the growth in capacity are presented in the Table 4.1 below.

Table 4.1
Developments in the Growth of Installed Capacity and Generation
(MW and GWh)

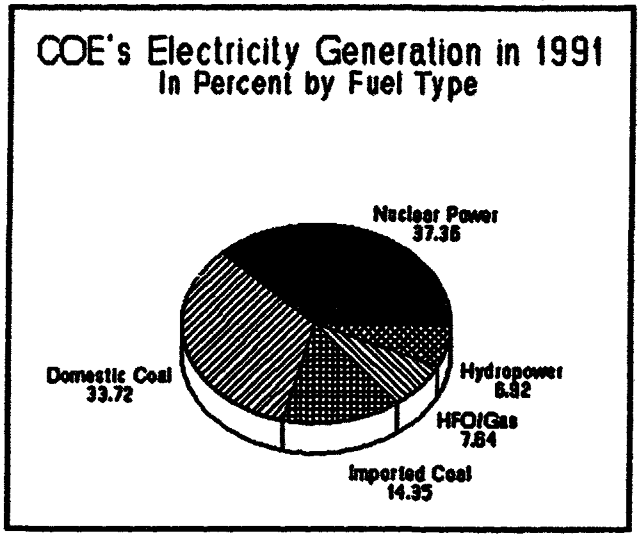
	1980	1985	1988	1990	1991
Hydro					
Capacity	1,868	1,975	1,975	1,975	1,975
Generation	3,713	2,236	2,596	1,851	2,441
Thermal					
Capacity	5,622	6,508	6,574	6,400	6,344
Generation	24,955	26,265	26,395	25,614	23,209
Nuclear					
Capacity	1,320	1,760	2,760	2,760	3,760
Generation	6,165	13,131	16,030	14,665	13,184
TOTAL					
Capacity	8,810	10,243	11,309	11,135	12,074
Generation	34,833	41,632	45,021	42,130	38,834

4.02 While the rapid growth in Bulgaria's nuclear capacity and generation, over the past two decades reduced the need for imported power or fossil fuels, it has resulted in considerable concern about the safety of the Kozloduy nuclear plant. In particular, the International Atomic Energy Agency (IAEA) in their 1991 report on this plant expressed concern about its condition, primarily the VVER 440s, units 1-4, which lack many safety features considered standard in the West. Over the past 18 months, major technical assistance has been provided for these units, primarily by the CEC, in conjunction with the World Association of Nuclear Operators (WANO) and their operations have been improved.

4.03 The issues involved in the safety of units 1-4 are difficult. In the short run, they are needed to meet peak winter demand due to: (a) operational problems with existing thermal plants; (b) fuel shortages; (c) the low availability of units 5 and 6; and (d) the high cost and uncertain availability of imports. In the medium term, with increased availability of power from the thermal plants and units 5 and 6, the need for the VVER 440s would greatly diminish. However, these units are one of the lowest cost source of power, aside from hydropower, for the country and their replacement by thermal power plants would involve a significant economic cost for the country. Nevertheless, the continued operation of these units in the medium term without major upgrading of their safety systems and perhaps even with it, would be unacceptable to much of the international community.

4.04 Chart 4.1 provides the details relating to fuels used by the COE to generate electricity in Bulgaria in 1991. The Kozloduy nuclear plant provided about 37% of the electricity, domestic lignite (mostly the Maritza East Complex), provided 33.7%, imported coal (mostly used at the Varna plant) provided 14.3% and there were small amounts generated by fuel oil, gas and by hydro plants accounting cumulatively for 14.6% of the total. Historically, very little gas has been used in power generation, with gas primarily reserved for industrial uses. While it would be advantageous, for environmental reasons, to expand gas usage in power generation, COE and NEK are opposed at this time to a major expansion because the country has only one source of supply, Russia, which is not viewed as being very stable (see para 3.15).

Chart 4.1



B. Primary Fuel Resources for Power Generation

B.1: Coal

4.05 Reserves. Bulgaria's only major domestic energy resource is low grade lignite. There are also moderate reserves of sub-bituminous coal, but the country is very poor in higher quality coal reserves. The minable reserves of the presently active coal mining areas are listed in Table 4.2 below. While these reserves may be recoverable with present technology, a significant portion probably cannot be recovered economically. In addition to the reserves listed below, there is a relatively new discovery of high quality hard coal in the northeastern part of the country. However, those reserves occur at great depth (about 2,000 m) and are, therefore, not economically recoverable.

Table 4.2: Bulgarian Coal Reserves

	Minable Reserves (mill. t)	Present Production (mill. t/year)	Lifetime (years)
Lignite	2,350	28	85
Sub-bituminous Coal	210	5	40
Bituminous Coal	10	<1	40
Anthracite	1	<1	20

4.06 The reserves of the major types of coal in active mining areas are briefly described below:

- Lignite reserves occur in two regions of the country: in Central Bulgaria, near Stara Zagora; and in Western Bulgaria, mainly West and South of Sofia. The central Bulgarian reserves are dominated by the large, open-pit minable deposit of Maritza East, which alone represent 2.2 billion tonnes, or 95% of all Bulgarian lignite reserves. These reserves are high sulfur (2%) with a low heating value (1500 kcal/kg) and a significant amount of these reserves are located under villages and towns. At this stage it is uncertain whether that portion will ever be exploited. However, during at least the next twenty years, exploitation is expected to continue under the present relatively favorable conditions, without major resettlements. Near Maritza East are the much smaller reserves of the Marbas underground mines, which cannot be exploited economically. The lignite reserves of Western Bulgaria are about 70 million tonnes, or only 3% of the country's lignite reserves. A major portion of these reserves, however, may be economically recoverable.

- Sub-bituminous coal reserves occur in Western Bulgaria, at Bobov Dol, Pernik and Pirin, and in Eastern Bulgaria, North of Burgas. The Bobov Dol reserves, at 160 million tonnes, are by far the largest, representing 75% of sub-bituminous coal reserves. The Bobov Dol reserves are marginal but some of the seams can probably be exploited economically. The other sub-bituminous reserves are very likely uneconomic.

- Bituminous coal reserves occur only in Central Bulgaria, North of Stara Zagora. Reserves are limited to about 10 million tonnes. Probably none of these reserves can be mined economically.

- Anthracite reserves occur only at a small deposit North of Sofia and are limited to only 1 million tonnes, which probably are not economically recoverable.

Use of Coal for Electricity Generation

4.07 As is shown in Chart 4.1, about 47% of Bulgaria's production of electricity comes from coal and lignite. Most of this is from domestic lignite/coal. There are two major power complexes that use domestic coal/lignite. These are the Maritza East Complex, consisting of three power plants (Maritza East I, II, and III, with 2270 MW capacity) and the Bobov Dol plant with 630 MW. Two power plants use imported coal namely Varna (1260 MW) and Ruse (400 MW). The paragraphs below discuss coal/lignite supplies for these plants and the best means of increasing them and, therefore, electricity output.

4.08 Maritza East. Current production from the Maritza East mines is about 23 million tonnes of lignite per year, while the generating plants at Maritza East could use substantially more than the 18-19 million tonnes they receive for electricity generation (part of the lignite is used for producing briquettes). Production from the mines, as a first step, could be raised to 28 million tonnes per year, the level of the record year 1987. The required increase in production could be attained from the three existing large open pit mines at Maritza East by increasing the annual average running time of the existing equipment by about 20% and the average hourly output by about 5%. This could be achieved through: (i) improved organization and management supported by technical assistance; and (ii) the purchase of certain critical pieces of imported equipment and increased availability of spare parts.

4.09 New mines at Maritza East and power plants based on these mines appear to be excluded by economic considerations. Given the high ratio of overburden to lignite, the low calorific value of the lignite and the high capital costs of a new mine, it would not be possible for a new mine to compete with imported coal. In addition, a new lignite-fired power plant would have higher capital and operating costs and lower efficiency than a new power plant burning imported high-grade coal. Finally, imported coal would be much preferable for environmental reasons: additional sulfur emissions would be much lower, and there would be no additional large scale use of land for open-pit mining.

4.10 Bobov Dol. For the Bobov Dol plant, probably the best option is to achieve full utilization by utilizing less coal from the Bobov Dol underground mines (most of which are uneconomic) and more lignite from the surface mines near Sofia, as well as suitable imported sub-bituminous coal, such as coal from Indonesia. While this option is significantly more expensive than full utilization of the Maritza East and Varna power plants (see below), it appears still preferable to the construction of new plant. Significant investments for coal blending and possibly also mill and boiler adaptation may be required. This should be carefully checked. Some old mining equipment at the lignite mines near Sofia would also have to be renewed. Full utilization of the Bobov Dol Plant (equivalent to an output increase of about 100 %) would require a substantial increase in coal availability. A blend of about 2 million tonnes per year of lignite from the surface mines near Sofia, 1.2 million tonnes from the Bobov Dol underground mine, and 0.7 million tonnes of high-grade imported sub-bituminous coal could be used (each coal type would contribute one third, in terms of heat content, to the plant's power generation). While such scenario would be compatible with modernization/restructuring of existing mines, boiler design may require different blending ratios (less lignite, more imported coal). Also, there may be constraints on Sofia basin lignite production which would change the blend in the same direction.

4.11 Varna. Continued operation of the Varna power plant on the basis of imported coal is almost certainly highly economic. It is important also that in future the coal supply be diversified. The single supply source historically (Donetsk basin of Ukraine) is becoming increasingly insecure, and its future competitiveness is highly doubtful. While Donetsk coal can be delivered by barge, future coal supplies are likely to arrive by medium size ship since many of the major alternative supply sources (US, South Africa, Columbia, Australia, Indonesia etc) are located at a considerable distance. The pier extension at the Varna plant to accommodate larger boats should, therefore, be completed with priority. Also, any new coal blending facilities and boilers at Varna should be adapted to use higher ratios of non-anthracite coal (while anthracite coal can presently be obtained internationally at low prices, there are only a few suppliers).

4.12 Ruse. Finally, for the Ruse coal fired power plant, it is probable that the analysis currently being undertaken by a consulting group may indicate that it is not economically justified to rehabilitate the plant. The plant's power generation capacity in 1991 was just 0.7 TWh (about 20% utilization of installed capacity). Coal supplies are uncertain, since the plant burns the same anthracite/low-volatility coal from the Donetsk basin as the Varna plant. Ruse or another nearby site may, however, be suitable for the construction of a gas-fired combined cycle plant or a dual-fired plant using both gas and imported coal. Delivery of the imported coal would, however, be expensive given the location of the plant on the Danube some distance from the coast and there are no likely sources of domestic coal.

4.13 Further development of Bulgarian coal resources appears not to be feasible, given the problems connected with Maritza East lignite, the limited reserves of the lignite mines near Sofia, and the uneconomic geologic conditions of all other deposits. If additional power plant capacity is needed, the best options would appear to be a new plant on the coast based on imported coal, or a new combined cycle gas-fired plant.

Costs of Coal Supply to Power Plants

4.14 Over the next 20 years, the lowest-cost fuel appears to be lignite from the existing mines at Maritza East, followed by lignite from the Sofia lignite mines, imported coal for the Varna plant, and lastly, coal imports for the Bobov Dol plant. A reduced amount of local coal from the Bobov Dol underground mines could possibly be produced at import parity cost, if the restructuring is implemented successfully (Tables 4.3 and 4.4).

Table 4.3: Typical Specifications and Prices for Imported Steam Coal

		Specifications						Prices			
		a/	b/			c/	d/	Present e/			Future f/
		Type	Heat Value	Ash	Moist.	Vol.	S	FOB	CIF	CIF	CIF
To	From		kcal/kg	%	%	%	%	$/t	$/t	$/Gcal	$/Gcal
Varna	South Africa	A	5,900 g/	20	10 g/	10 g/	1.0 g/	19	38 h/	6.4	6.2 i/
Bobov Dol	Indonesia	S	5,500	1	22	40	0.1	23	43 j/	7.8	9.4 k/

a/ A - Anthracite, S - Sub-bituminous
b/ lower heating value
c/ volatiles
d/ sulphur
e/ mid/1992 prices
f/ in constant 1992 terms, assumed to be 10% higher than 1992 prices (FOB quotations are low in comparison with other sources and sea freight rates are unusually low in 1992)
g/ estimated
h/ landed in Varna West, then by rail to Varna plant, high sea freight due to small size boat (15,000 t)
i/ sea freight and Varna port costs reduced by 5 US$/t (mid-92 basis) due to larger boats unloaded at Varna TPP, pier extension to 30,000 t completed 1994
j/ landed at Burgas in boats up to 50,000 t, then transported by rail to Bobov Dol
k/ rail charges from Burgas to Bobov Dol doubled (from 4 to 8 US$/t)

Table 4.4: Production Costs of Selected Bulgarian Coal Mines

						Future b/		
		Output	Costs			Output	Costs	
	kcal/kg	Mt/a	L/t	$/t	$/Gcal	Mt/a	ex mine US$/Gcal	deliv. $/Gcal
Maritza East	1500	22.9	90	3.8	2.5	28.0 c/	4.2 d/	4.2
Sofia Lignite Mines e/	1900	1.6	140	5.8	3.1	2.0 f/	5.1 g/	6.2 h/
Bobov Dol	1900	1.5	530	22.1	11.6	1.2 i/	9.3 j/	9.3

a/ output and costs based on extrapolation of first 9 months of 1992
b/ about next 20 years, costs in constant 1992 terms
c/ historical (1987) record production level, to be re-gained by organizational/managerial improvements and minor investments for auxiliary equipment
d/ costs increased by 67%, to cover the costs of recurring minor replacements and modernization as well as of recultivation and compensation for used land, based on COE estimate
e/ comprising the Chukurovo, Stanjanci and Beli Brec surface mines
f/ 20% output increase assumed to be achieved by partial replacement of old equipment
g/ costs increased by 67%, to cover the costs of recurring minor replacements and modernization as well as of recultivation and compensation for used land, assumed to be same increase as for Maritza East
h/ average transport cost of 2 US$/t to Bobov Dol TPP assumed
i/ 20% output decrease assumed to be required (abandonment of worst mine sections)
j/ 20% unit cost reduction after restructuring assumed (concentration on best portion of deposit)

4.15 For Maritza East lignite, the average unit production costs will probably rise to 6.3 US$/t, or 4.2 US$/Gcal in the short-term. This will be necessary to cover all recurring expenses for land use and replacement/modernization of most equipment, including funds for some rehabilitation which will raise, at low cost, the production level to about 28 million tonnes per year. While some minor further expansion of the existing mines beyond 28 million tonnes per year might be feasible, major further expansion would require adding additional major mining equipment to the existing mines or building new mines. While this would be technically possible, given the relatively high overburden/lignite ratio and the high capital cost of the major equipment, the marginal cost of production for the extra output would be expected to be near or even above the costs of coal imports (about 8 US$/Gcal or 12 US$ per tone of lignite). This appears, therefore, not to be an attractive alternative.

4.16 For the lignite surface mines near Sofia, average unit production costs will probably rise to 5.1 US$/Gcal ex-mine, or 6.2 US$/Gcal delivered at the Bobov Dol plant. The increase will be required to pay for replacement of some old equipment and for improved land reclamation. The deliveries from the Sofia lignite mines to the Bobov Dol plant would then be as expensive as coal imports to the Varna plant, but still significantly cheaper than coal imports to the Bobov Dol plant.

4.17 For the Bobov Dol underground mines, serious restructuring may lead to a future production cost of 9.3 US$/Gcal, equivalent to the cost of imported sub-bituminous coal for Bobov Dol. Successful restructuring requires concentration on the best sections of the deposit, abandonment of uneconomic sections, and government assistance for solving the social problems of redundant mine labor.

B.2: Nuclear Fuel

4.18 Nuclear fuel is provided from the Russian Republic in the form of ready to use assemblies designed specifically for the VVER reactor. Different designs are utilized in the 440 series as compared to the 1000 series. Each 440 series reactor has about 325 assemblies which are replaced on a 3-year cycle (about 100-110 per year). Recent prices paid to Russia were about US$150,000 per assembly. The 1000 series reactors have 255 larger assemblies which also follow a 3-year replacement cycle and recent costs are US$500,000 per assembly.

4.19 In a normal year, this represents a total fuel cost of around US$150 million for the quantities used and this price is consistent with present uranium costs of US$60-80/kg. Overall quantity requirements are not significant in the present world market.

4.20 The assemblies are specifically designed for the VVER reactors. It is very unlikely that an alternative source of supply other than Russia will be found for the 440 series. For the 1000 series, discussions have been held with West European suppliers, but it is only likely that alternative sources will prove practical if a sufficiently large market can be found.

4.21 Consequently, it is probable that Russia will remain the sole supply source. The fuel is contracted on a two-year lead time, and arrangements are in hand for 1993 and 1994, although prices need to be more clearly determined. This arrangement is likely to continue for the foreseeable future.

B.3: Natural Gas

4.22 Bulgaria used 5.67 bcm of gas in 1991 and demand is expected to remain flat (at 5.6-5.7 bcm) in 1992. Of this total, around 4.5 bcm is used by district heating plants, which are often CHP plants, and by industrial co-generators. Based on electricity produced, about 1.0 bcm equivalent of this 4.5 bcm are used for generating electricity. Current prices paid for Russian gas are adjusted every three months, using a base price of US$90 per thousand cubic meters (tcm) indexed to the price of residual fuel oil with 1% sulphur content, the price of residual fuel oil with 3.5% sulphur content, and to the price of gas oil. Based on this formula, the price for the fourth quarter of 1992 is just slightly above the base. Over half of the gas is currently not actually paid for, but is obtained as debt repayment for the assistance that Bulgaria provided in the construction of the Yamburg pipeline and as a transit fee for gas passing through Bulgaria to Turkey. The remaining gas is paid for in a barter arrangement. Gas is sold by Bulgargaz, as required by the Government, at 70% of the price of 3.5% sulfur heavy fuel oil on a heat equivalent basis.

4.23 Options to build new gas-fired power plants are somewhat limited by the capacity of existing pipelines. New plant construction may be feasible for a plant in the northeast corner of the country using an estimated maximum available pipeline capacity in the Russian pipeline to Bulgaria of 1.5 bcm/yr. However, given the high efficiency of gas-fired combined cycle plants, this gas could produce of about 6.5 TWh of electricity. Additional gas-fired capacity would require either the construction of an additional pipeline through Romania (about 180km) or the use of available capacity in the transit pipeline from Russia to Turkey and Greece. Construction prospects for a new pipeline through Romania are not thought to be very good, while currently available transit capacity, which represents about 50% of a total transit capacity of 10 bcm, is dependent on the growth of gas contracted to be deliver to Greece and Turkey. As this grows, the amount of transit capacity available to Bulgaria will diminish. Under current plans, this available transit capacity would be gone in about 8-10 years. It is, therefore, questionable whether the Bulgarians should rely on it.

4.24 Bulgaria's gas demand is winter-peaking since a substantial part of it is used for producing hot water for district heating systems. Current capacity of the line from Russia and draw down of storage at the Chiren gas storage field is barely adequate to meet peak demand. It will probably be necessary to increase the capacity of the Chiren field to provide peak gas and this would be especially true if a new gas fired power plant were built.

4.25 Russia is currently the sole source of gas for Bulgaria which substantially increases the risks associated with gas supplies. Also, the pipeline route crosses Ukraine, Moldova and Romania which further increases risks. In addition, the long run price of gas from Russia and the quantities available are uncertain. (However, there is a possibility that the current active exploration program in Bulgaria by international oil companies will find gas.) For the purposes of the analysis, it was assumed that gas would be available at a long run price of about US$4.00 per MMBTU on the Bulgarian/Romanian border (equivalent to about US$128 per thousand cubic meters). This is consistent with the assumptions used in calculating the long run price of Russian gas supplied to the Ukraine.

C. Generation Capacity

C.1: Nuclear Power Plants

4.26 Background. The only nuclear plant in Bulgaria is owned by the National Electric Company (NEK) and is situated at Kozloduy, about 220 km north of Sofia on the Danube river. It comprises 4x440 MW and 2x1000 MW units with a total installed capacity of 3,760 MW. All units are pressurized water reactors (PWR) utilizing slightly enriched uranium as fuel and light water as moderator and coolant. The four 440 MW units--units 1, 2, 3 and 4--were commissioned in the years 1974, 1975, 1980, and 1982 respectively. Unit 5 (VVER-1000) was commissioned in December 1988. Unit 6 is operating at partial output, but as of April 1993, it had not yet been allowed to attain full power and it had not been officially commissioned.

4.27 The performance of units 1-4 over the past few years has been quite good: for example, the average plant load factor for units 1-4 was 79.6% in 1987, 76.0% in 1988, and 71.2% in 1989. The performance of unit 5 over the quite limited time period in which it has been operating has not been as good, due largely to initial problems with the steam generators. The Kozloduy plant is being used as a baseload plant and has a good record of unplanned reactor scrams (2-3 per reactor per year).

4.28 The Kozloduy units 1 to 4 are of the early VVER-440/model 230 design, developed by the Soviets in the 1960s and 1970s and lack safety features such as containment, which are considered essential in the west. Along with other units of the same type,[2] they have been the focus of international concern during the past years. In addition, a number of managerial, training and material problems exist at these units. While the VVER-1000 units do not have the same design deficiencies as the VVER-440s model 230s, they have instrumentation and control deficiencies, steam generator problems and suffer from many of the same managerial, training and material problems as the VVER-440 units.

4.29 The COE had planned for a second nuclear power site on the Danube at Belene, consisting of two VVER-1000 units in phase 1 and two additional units in phase 2. A considerable amount of equipment was ordered and paid for which was to be used for unit 1 and some construction at the site has taken place. However, in view of: 1) the drastic political changes which have occurred in the country, 2) safety concerns about nuclear power, and 3) the major economic changes which are ongoing in the country and will result in lower electricity demand, the Government of Bulgaria decided to stop construction of the Belene plant.

C.2: Thermal Power, District Heating and Industrial Cogeneration Plants

4.30 Thermal Power Plants. The following is a list of thermal power plants, all of which are owned and operated by the National Electric Company, NEK:

(a) Maritza East 1. The plant has been in operation for years and has reached the end of its useful life. The plant has four 50 MW units supplying steam to a near by briquette factory and two units of 150 MW plant which have been decommissioned. The fuel is lignite from the adjacent mines. The units in this power station are planned for decommissioning during 1995-1997. For this study, it was assumed that this plant will be replaced by a new lignite-fired 400 MW condensing power plant which will commence commercial operation by January, 1999.

(b) Maritza East 2. The plant has four 150 MW units (units 1-4) which have been converted to direct firing of lignite, three 210 MW (units 5-7) units and a 210 MW (unit 8) under construction. The first four units have nearly completed half of their operating life and are candidates for life extension. The first four units of 150 MW each are expected to undergo life extension through rehabilitation during 1994-1998. The three units of 210 MW each are relatively new and are operating well. Another unit of 210 MW capacity is to be completed with financing from EBRD and EIB. This unit and unit 7 which share a common stack will be provided with flue gas desulfurization (FGD).

(c) Maritza East 3 has four units of 210 MW each and were installed during 1978 through 1981. The units are operating well and standard rehabilitation and modernization of instruments and controls are anticipated in the near future. Retrofitting of these units with FGD is being considered. Lignite supplied is similar to that supplied to Maritza east 1 and 2.

(d) Varna has 6 units of 210 MW, each installed between 1968 and 1979. They are designed to use Ukrainian anthracite coal with units 4 to 6 designed also to use natural gas. Difficulty in supplying this coal is causing problems in the operation of this plant. Units 1 to 3 are in poor technical condition. In this study, it is recommended that the first

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2 In addition to the Kozloduy units 1-4, the following units of the same type are still in operation: at Bohunice, Czechoslovakia 2 units; at Novovoronezh, Russia, 2 units; and at Kola, Russia, 2 units. The

three units be rehabilitated to burn low sulfur imported coal and the other three units undergo life extension through rehabilitation and continue to use the present imported Ukrainian coal. Use of natural gas is not recommended for power production in these units since it is substantially more expensive than coal on a heat basis and Varna cannot take full advantage of the gas (see para 4.11).

(e) Bobov Dol has three 200 MW units, each commissioned between 1973 and 1975. Bobov Dol mines are depleted and alternate sources of fuel supply and utilization are being evaluated. Boiler deterioration due to heavy slagging has been reported. These units are scheduled for life extension through rehabilitation during the years 1994 to 1996. The boilers require modifications to accept blended coal or low sulfur imported coal (see para 4.10).

(f) Ruse has two units of 30 MW each, two units of 110 MW each and two units of 60 MW each. The 30 MW units were rehabilitated and are planned to be decommissioned by 2000. The current technical condition of the 110 MW units is poor. The 60 MW units are operating well. The power plant uses anthracite coal imported from Ukraine. Availability of this coal has been a big problem for Bulgaria. Studies are being undertaken to convert the existing boilers to burn imported sub-bituminous coal. Some of the units could be converted to gas firing but it is not recommended. If continued use of gas is considered, combined cycle repowering may be technically and economically justifiable. The rehabilitation of these units are scheduled during 1995-2000. The two 30 MW units are expected to be retired during the period 1998-2000. In this study, a recommendation is made to convert and to extend the life of the two 60 MW and the two 110 MW units to burn low sulfur imported coal.

(g) Maritza 3 has two units of 25 MW each, commissioned during 1951-1955 and both have reached the end of their useful lives. It also has one 120 MW unit, commissioned in 1971, which has severe boiler and turbine problems. This plant supplies steam to the district heating system. The 120 Mw unit has been derated to about 75-80 MW. The deration is mainly due to bad fuel quality. Lignite fuel is supplied by Maritza West coal-mine and contains excessive amounts of over burden, as well as being expensive to produce. The plant is located in one of the most polluted areas of Bulgaria. Natural gas is available at the site. Therefore, it may be economically feasible to install a combined cycle cogeneration system consistent with the steam demand for the district heating and industrial systems. However, in this study an assumption is made to retire these units and lost electricity capacity will be made up by a newly installed 400 MW plant in the Maritza East 1 complex.

District Heating Plants

4.31 There are several district heating cogeneration plants that produce electricity as a byproduct. The plants supply hot water for heating the buildings and process steam for local industries. There are several other district heating plants that produce only hot water and/or process steam. Most of the heat and electricity is produced by plants using natural gas as a fuel. The plants that use natural gas as fuel (both cogenerating and plants that produce only thermal energy) provide the potential for converting and/or repowering to efficient gas turbine cogeneration. Detailed feasibility studies and audits of these plants are warranted to define economically feasible repowering opportunities.

4.32 The major cogenerating district heating plants which could be converted to combined cycle plants are in Sofia (Sofia, Traicho Kostov plants) Plovdiv, Pleven and Shumen and are described below. Also the Republika plant in Pernik, which uses local coal is discussed.

(a) The Sofia plant is ideal for conversion to gas-fired combined cycle cogeneration. There are currently four operating units at the plant, three rated at 25 MW each and one rated at 50 MW. Units 4 and 5 are scheduled to be retired during 1994. Units 6 and 8 are recommended to be rehabilitated and repowered during 1995 and 1996 using gas turbines. A preliminary estimate for gas turbine repowering of 6 and 8 results in an increase in net electric generating capacity of about 280 MW based on current operations. The new net capacity for this plant after the retirement of units 4 and 5 is about 345 MW. The current estimate for repowered capacities were made consistent with the current design steam demands.

(b) The Traicho Kostov plant has five units. Four units have turbine generators each rated at 30 MW each and one rated at 66 MW. This plant uses natural gas as the primary fuel. The four 30 MW turbines need rehabilitation, especially replacement of HP cylinders. Like the Sofia plant, this plant is an ideal candidate for rehabilitation and repowering with gas turbine combined cycle cogeneration. All the existing five units offer a potential for gas turbine combined cycle cogeneration. The estimated net capacity increase is about 735 MW. The estimated new net capacity for this plant is 870 MW.

(c) The Republika plant is located in Pernik, a major industrial town outside Sofia. This plant utilizes local low grade coal with high content of moisture, ash and sulfur. This plant supplies heat to a population of about 100,000 and process steam to several industries. Due to age, this plant is currently operating far below capacity. The current installed and available electric generating capacities are 155 MW and 75 MW respectively. The plant has five units of which unit 1 is retired and unit 2 is scheduled to be retired in 1993. Units 3, 4 and 5 are scheduled to be rehabilitated during 1994 and 1995. Also a new 25 MW cogeneration unit (most of the equipment on site) is scheduled to be installed in 1995.

(d) The Plovdiv plant has two 30 MW units and a 25 MW unit which is partially completed. The fuel is heavy fuel oil but permits have been obtained to convert to natural gas. Because of availability of natural gas an early implementation of combined cycle operation would be beneficial with the result of increased electricity production at high efficiencies. Unit 1 is scheduled to be retired in 2005. Strong recommendations are made to repower units 2 and 3 during the years 1996 and 1998, respectively. The new net repowered capacity is estimated to be about 260 MW.

(e) Pleven & Shumen. Currently, Pleven plant has three 12 MW installed units with maximum generating capacity of 8 MW for each unit. Similarly, Shumen has three 6 MW units with maximum generating capacity of about 4 MW each. In both the plants, large quantities of steam are sent to industries after expanding through back pressure turbines. These plants use natural gas and oil for fuel. Both these plants offer a potential for repowering. The estimated new net capacities for Pleven and Shumen are about 295 MW and 160 MW respectively.

Industrial Plants

4.33 The major industrial plants that produce electricity in a cogeneration mode are: the petroleum and petrochemical processing plant in Burgas, chemical plants in Devnia, a chemical plant in Svishtov, a metallurgical plant in Kremikovsi, a petrochemical plant in Pleven, a tires and fabric plant in Vidin, a chemical plant in Vratsa and a fertilizer plant in Stara Zagora. In 1991, all these plants combined with other smaller facilities generated about 3.5 TWh. The reported total installed capacity for industry for the same year is 1040 MW. This resulus in an annual utilization of 3400 hours for the total installed capacity.

4.34 The plants at Burgas, Devnia, Kremikovsi and Stara Zagora use or have an option to use natural gas as the primary fuel. Therefore, these plants are candidates for gas turbine combined cycle repowering. Preliminary estimates for repowering capacity were made by matching gas turbine/heat recovery steam generator output to the rated conditions of existing steam turbines. Gas turbine and waste heat boiler capacities were determined by prorating the performance of a standard industrial gas turbine. Table 4.5 shows preliminary estimates for repowered capacities and costs for installation.

4.35 As indicated above, the current analysis of district heating and industrial cogeneration plants has indicated a potential to increase the electricity generating capacity of Bulgaria through repowering. The estimated maximum potential for increase in total net capacity is approximately 3900 MW, at an average net heat rate of less than 1500 kcal/kWh. This estimated capacity is expected to be the maximum potential and may not be realizable after a more detailed study is performed. Even if one intuitively assumes that half this capacity is feasible, then it would represent a substantial percentage of the total generating capacity in Bulgaria. The average estimated cost for repowering is US$375/kW. The fuel cost is estimated to be 2.4 cents/kWh, based on US$4/million BTU. The capital charge, based on 10% interest and 25 year plant life and 6000 hours of operation each year, is estimated to be .7 cents/kWh. The total cost for electricity production excluding operating (non fuel) and maintenance cost is 3.1 cents/kWh which is very attractive to any country that adopts free market practices. The above estimates are very preliminary and detailed audits of plants and feasibility studies are required to establish real opportunities. In addition, these repowered plants are less polluting than coal fired plants as they do not emit sulfur dioxide and do not have solid waste disposal problems.

4.36 NEK and the COE are less optimistic than the Bank about the potential for repowering and rehabilitating industrial and district heating plants. They believe it will cost more, will be institutionally more difficult (since these units are not part of NEK though power purchase arrangements exist), that the increased reliance on imported gas is undesirable. Therefore, in the analysis described in Chapter 5, alternative cases were run excluding this option.

C.3: Hydropower Plants

4.37 Background. There are 1,970 MW of hydroelectric capacity in Bulgaria, making up approximately 18% of the NEK's total installed capacity. Altogether, there are 87 operating hydroplants, however, the 11 largest plants have 77% of the capacity. The largest single hydropower project is the Belmeken-Sestrimo-Chaira hydropower complex (Rila complex) located in the Rila mountains. It currently has 735 MW of capacity split into three separate plants (Belmeken, Sestrimo, Momina Klisura) and accounts for 37% of Bulgaria's hydro capacity. The second big hydro power complex is the so called Vatcha or Rhodope complex located in the Rhodope Mountains with four operating power plants (Dospat-Teshel, Devin, Antonivanovtsi, Krichim) and total capacity of 380 MW. The third large complex is the Arda river complex with three power plants (Studen Kladenets, Ivailovgrad and Kardzhali) with a total capacity of 274 MW. The available hydro capacity depends largely on the water supply in the reservoirs. In the winter of 1991-92, available hydroelectric capacity was between 750 and 900 MW, well below the total installed capacity, due to the drought in Bulgaria in 1990 and earlier which resulted in the partial depletion of the reservoirs. These capacity figures are based on normal operations on a monthly basis that would meet spring minimum reservoir levels needed for municipal and agricultural supply. In fact, instantaneous capacity can and did increase to approximately 1500 MW or above, though at a penalty to generation during other periods if minimum reservoir levels are to be met.

Table 4:5: <u>Hydro Power Stations in Operation (over 5 MW)</u>

No	No. of Stat	River Basin	Hydro Power Station in Operation Over 5 MW	In Operation Since (year)	Installed Capacity (MW)	Design Annual Generation (GWh)	Actual Average Annual Generation (GWh)	Actual vs Design Generation
1	78	Rilska	Pastra	1924	5.50	29.00	29.80	102.76%
2	18	Iskar	Simeonovo	1927	6.28	49.00	35.41	72.27%
3	79	Rilska	Rila	1929	10.90	41.50	47.76	115.08%
4	56	Vatcha	Vatcha - 1	1933	14.00	21.60	21.88	101.30%
5	17	Iskar	Mala Tsarkva	1934	7.80	43.00	38.90	90.47%
6	59	Chaya	Asenitsa - 1	1951	7.20	30.00	24.94	83.13%
7	1	Lom	Kilka	1952	5.45	14.00	13.77	98.36%
8	32	Rositsa	Rositsa - 1	1954	7.50	22.00	21.94	99.73%
9	63	Tundja	G.Dimitrov	1955	7.00	17.00	13.00	76.47%
10	64	Tundja	Stara Zagora	1955	22.40	72.00	59.24	82.28%
11	6	Barzia	Barzia	1956	5.90	34.00	24.52	72.12%
12	19	Iskar	Pasarel	1956	32.50	77.00	68.52	88.99%
13	20	Iskar	Kokalyane	1956	22.40	73.00	73.78	101.07%
14	5	Barzia	Petrohan	1957	8.00	33.00	25.03	75.85%
15	16	Iskar	Beli Iskar	1957	16.80	42.00	29.81	70.98%
16	48	Stara	Batak	1957	40.00	167.70	126.62	75.50%
17	71	Arda	Studon Kladene	1958	62.40	217.00	189.76	87.45%
18	49	Stara	Peshtera	1959	128.00	440.74	339.66	77.07%
19	50	Stara	Aleko	1959	64.80	202.05	138.19	68.39%
20	57	Topolnitsa	Topolnitsa	1962	8.00	29.00	21.56	74.34%
21	70	Arda	Kardjaly	1964	106.40	165.00	114.34	69.30%
22	65	Tundja	Jrebtchevo	1965	14.40	32.60	16.38	50.25%
23	72	Arda	Ivailovgrad	1965	108.00	217.00	175.72	80.98%
24	80	S.Bistritsa	Popina Laka	1969	21.50	71.40	57.05	79.90%
25	81	S.Bistritsa	Lilyanovo	1969	20.00	69.50	57.41	82.60%
26	82	S.Bistritsa	Sandanski	1971	14.20	48.10	38.66	80.37%
27	51	Vatcha	Teshel	1972	60.00	166.20	102.10	61.43%
28	55	Vatcha	Vatcha - 11	1972	7.00	21.35	16.49	77.24%
29	54	Vatcha	Kritchim	1973	80.00	197.40	164.93	83.55%
30	46	Sestrimska	Sestrimo	1974	240.00	421.00	221.00	52.49%
31	47	Kriva	Momina Klisu	1974	120.00	198.00	109.00	55.05%
32	53	Vatcha	Antonivanotsi	1975	160.00	245.00	167.90	68.53%
33	45	Kriva	Belmeken	1976	375.00	556.00	306.00	55.04%
34	87	P.Bistritsa	Spantchevo	1981	28.00	95.00	55.64	58.57%
35	52	Vatcha	Devin	1984	80.00	122.00	69.80	57.21%
36	86	P.Bistritsa	Pirin	1992	21.20	70.80	0.00	0.00%
				TOTAL	1938.53	4350.94	3016.51	69.33%

4.38 In 1991, which was a moderately dry year, hydroelectric plants in Bulgaria generated 2.4 TWh of total electricity, which was 6.2% of total electricity generated in the country. Based on the rated capacities of installed units, hydroelectric plants should generate 4.5 TWh in average precipitation years and 1.9 TWh in dry years. It appears that the economically exploitable hydropower potential in Bulgaria is approximately 10-12 TWh. However, this figure depends very much on the changing economics of hydropower and the value of the services it provides in addition to energy, some of which are instantaneous start-up, operational flexibility, load-following capability, peaking operability in a stop-start mode, and load management through pumped storage.

4.39 Considerable hydropower capacity is under construction or design in Bulgaria. Pumped storage capacity of 864 MW are under construction at Chaira which is part of the Belmeken-Sestrimo-Chaira complex. The first two units at Chaira, 2 x 216 MW, are almost complete and NEK has indicated that they will be completed by April 1993. The other two units, also 2 x 216 MW, are scheduled to be completed in 1995 with financing provided by the Bank.

D. Transmission, Interconnection and Trade

D.1: The Current Transmission System

4.40 The high voltage systems consist of 400 kV and 220 kV systems, but with one 750 kV interconnection (tie line). The subtransmission level is 100 kV and lower. In this report, attention is focused entirely on the 400 kV and the 220 kV system (the High Voltage system) which constitutes the bulk power transmission system. Both the 400 and the 220 kV systems form a closed loop configuration respectively, which essentially cover the entire country. The 220 kV system has several alternate paths that connect intermediate nodes of the main loop. The transmission system is not a bottleneck. Adequate transmission capacity is available to meet demand, though certain rehabilitation needs to be undertaken (see below).

D.2: Current needs 400/220 kV transmission system

4.41 With regard to the present day 400/200 kV system, a number of short-term needs have been identified. These needs can be divided into two categories. The first consists of rehabilitation actions that will make the existing system more reliable, easier to maintain, and up to the current accepted practice. Examples include:

- Replacing sections of the 400 kV conductors.
- Replacing sections of the 400 kV ground wires.
- Changing 110 kV towers built before 1970.
- Upgrading shunt reactors.
- Changing circuit breakers

The costs for the first three items is estimated by Bulgaria to be US$20-25 million, while the initial cost of replacing failed reactors is estimated to be US$10 million. The circuit breaker upgrade should start in two to three years, but no cost estimates are currently available. It should be noted that the rehabilitation can proceed incrementally. A careful analysis of where the process should start and how it should continue should be undertaken as a first step. It is perhaps worth nothing at this point that a significant portion of the transmission equipment is reaching the end of its useful life and will need upgrade/replacement within the next few years. The second category of needs is related to expansion/enhancement of the current high voltage network. In spite of the drop in demand some expansion and enhancement remains necessary. There is a need for additional shunt reactors to maintain the voltage at acceptable levels and these will be financed by the Bank. The construction/completion of the Plovdiv/Korlovo Zlatitsa 400 kV lines and stations will provide an alternate 400 kV path linking the pumped hydro plant at Chaira to the NPP Kozloduy. This will enhance the effectiveness of the pumped hydro plant/NPP combination for peak sharing and regulation reserve availability.

D.3: Interconnection and Electricity Exchanges

4.42 The Bulgarian power system is interconnected with all neighboring countries including Ukraine, Romania, Turkey, Greece, and Yugoslavia. The country is linked with Ukraine through a 750 kV line and a 400 kV line, with Romania through two 400 kV lines and a 220 kV line, and with Greece, Turkey and Yugoslavia through 400 kV transmission lines. In the past, about 800 MW could be imported from the FSU (Ukraine) at periods of peak demand with about 4-5 TWh imported yearly. Although the contract was to be renewed annually, experience in 1991 and 1992 suggests that Ukraine may be unable or unwilling to provide the energy and capacity that was previously supplied and for which the 750 kV transmission line was originally installed.

4.43 Bulgaria's trade in electricity with Romania, Greece, Turkey and Yugoslavia remains small. Trade with Romania will remain very limited because both countries suffer from available capacity shortages, while electricity trade with Turkey is limited by technical factors and costs. Trade with Greece is limited primarily by capacity constraints in that country while trade with Yugoslavia is stopped by the current embargo.

4.44 The interconnections to the Ukraine and Romania are in parallel (synchronized systems) whereas those to Yugoslavia and Greece are operated on the "isolated island" principle which allows synchronized operation of an isolated part of one power system with the other. The "isolated island" method of operation limits flexibility and Bulgaria's ability to import power and energy, but this is necessitated by the fact that Bulgaria (as well as the other countries of the former CMEA) belongs to the Eastern Europe interconnected system known as IPS or more informally as MIR (Peace); whereas Greece and Yugoslavia belong to the Western Europe interconnected system known as UCPTE. The difference in the standards of the two systems does not allow synchronization of the systems at the present time. Turkey, on the other hand, is not a member of either system and operates its own independent power grid. This gives it more flexibility to interchange power with either system. However, being a member of a large system has major advantages in that the immediate availability of power through the system interconnections contributes to a higher reliability than would be the case without them and, if rationally utilized, also to a more economic operation of the interconnected system.

4.45 Bulgaria is in tripartite discussions with Greece and Yugoslavia for enhancing future exchanges, strengthening of the interconnections and possible synchronization. This would require the adoption by Bulgaria of the UCPTE standards including adequate generating capacity, peaking units, and frequency and voltage regulation which they currently cannot meet. Also at present, it is questionable whether Bulgaria could do without imports of electricity from Ukraine at peak periods and, therefore, it may not be able to join UCPTE until that issue is resolved. There are, however, ongoing discussions between UCPTE and IPS about establishing closer links and eventually even synchronizing the two systems and if this occurs it would eliminate the necessity for Bulgaria to make a decision between the two systems. The completion of the improved control system for NEK, which will be financed by the Bank, will facilitate Bulgaria's consideration for membership in UCPTE at a later date, and assist parallel operation of the Bulgarian power network with the UCPTE network.

4.46 Trade Arrangements. All of Bulgaria's imports and exports of electricity are on an ad hoc basis, except for a bilateral trade arrangement with the Ukraine. In the past the trade arrangement was with the FSU which also, as part of the IPS, provided reserve capacity and frequency control. Arrangements with the independent Ukraine are more uncertain than with the FSU, but Bulgaria has a bilateral trading arrangement under which it sells a range of products to the Ukraine (food, chemicals etc.) in return for Ukrainian products including electricity. Goods and services under this bilateral trading arrangement are priced in dollars based on world market prices and each country is supposed to import about the same value of goods from the other country so there should be no net surplus. For the purposes of this analysis, it was assumed that 400 MW of capacity and 2 TWh of electricity yearly would be available from the Ukraine over the time period of the study at a cost of about 3.5 US cents/kWh.

V. SUPPLY/DEMAND BALANCE ANALYSIS

A. Assumptions and Methodology

5.01 This chapter describes the results of the generation power system planning analysis on the Bulgarian power sector. The primary objective of this analysis has been to evaluate the implications in terms of operating and investment costs of adopting alternative scenarios for the rehabilitation or closure of the Kozloduy nuclear power unit (nuclear supply scenarios).

5.02 Methodology. Three demand forecasts have been agreed with NEK, along with six scenarios for Kozloduy creating a total of 18 cases (6x3). For each case a least-cost electricity supply plan has been developed. The existing thermal plant has been analyzed and data prepared on present plant performance and the scope for rehabilitation or repowering. Projections of future fuel availability and costs have been prepared. This data has been incorporated in the WASP-III generation planning model. Analysis has been carried out for each of the cases to determine the least-cost means of meeting future demand for electricity. The analysis has been carried out over a planning period to 2010, and the costs of investment and operation discounted at 10% and compared on a present value basis.

5.03 The Nuclear Plant Scenarios. Six different nuclear plant scenarios have been received from the Bulgarian Government and analyzed. These cover the complete spread of options from an immediate cessation of nuclear power generation to maintaining the full nuclear sector. The options include safe shut down, maintaining the plant in a safe condition and eventual decommissioning. Consideration has also been given in the costings to strategies for upgrading the plant to acceptable safety standards.The scenarios are:

Scenario 0 - All six units at Kozloduy cease power production immediately, no further nuclear developments.

Scenario 1 - Kozloduy units 1 to 4 cease production immediately, Kozloduy units 5 and 6 continue production to design end of life.

Scenario 2 - Kozloduy units 1 and 2 cease power production immediately, 3 and 4 cease power production in 1/1/98, units 5 and 6 continue operation through to end of design life.

Scenario 3 - Kozloduy units 1 to 4 cease power production in 1/1/98, units 5 and 6 continue operation through to end of design life.

Scenario 4 - Kozloduy units 1 and 2 cease power production in 1/1/98, units 3 to 6 continue operation through to end of design life.

Scenario 5 - All six units continue operation through to end of design life (2005 for unit 1, 2006 for unit 2, 2011 for units 3 and 4 and about 2019 for units 5 and 6).

In all these scenarios, no investment in new nuclear units was considered. However, an additional scenario was considered at the request of the Bulgarian authorities and that was **Scenario 6** - All six units continue operation through to the end of their design life, and additional nuclear units would be considered as candidates for new plants. In fact, that turned out to be the same scenario as scenario 5, since new nuclear plants were not a least-cost solution.

5.04 Units 5 and 6 continue operation to about 2019, that is 30 years life. Analysis has been carried out by NEK and their consultants on estimated availabilities, operating, upgrade and safety works costs for the nuclear units under the different scenarios. The annual investment cost for each scenario are summarized in Table 5.1.

Table 5.1: Nuclear Safety/Upgrade Investment Costs (US$M)

	Scenario					
Year	0	1	2	3	4	5
1993	23.3	35.0	47.5	60.0	65.0	85.6
1994	16.3	30.0	54.3	78.1	63.1	150.6
1995	11.7	37.5	62.3	88.1	128.1	190.0
1996	11.7	97.5	113.8	130.0	160.0	165.0
1997	11.7	117.0	133.8	150.0	150.0	90.0
1998	0.0	50.0	57.5	65.0	77.5	75.0
1999	0.0	35.0	40.3	45.5	60.3	60.0
2000	0.0	20.0	23.8	27.5	43.8	60.0
2001	0.0	20.0	23.8	27.5	43.8	115.0
2002	0.0	75.0	78.8	82.5	98.8	60.0
2003	0.0	20.0	20.0	20.0	40.0	67.5
2004	0.0	20.0	20.0	20.0	40.0	65.3
2005	0.0	20.0	20.0	20.0	40.0	63.8
2006	0.0	20.0	20.0	20.0	40.0	63.8
2007	0.0	20.0	20.0	20.0	40.0	63.8
2008	0.0	20.0	20.0	20.0	40.0	63.8
2009	0.0	20.0	20.0	20.0	40.0	63.8
2010	0.0	20.0	20.0	20.0	40.0	63.8
Total	74.7	678.0	796.4	914.2	1,210.4	1,566.8

5.05 Annual operating costs include the costs for nuclear fuel which are estimated in 1992 prices at US$16 million per unit for units 1 to 4, and US$43 million per unit for units 5 and 6. These values have been reflected in the generation planning data. O and M costs have been based on historical figures, and are estimated as Lv 840 million per year for all six sets, or Lv 270 million for each pair of units 1 to 4, and Lv 300 million for units 5 and 6. These are at 1992 price levels and have been converted to US Dollars at the exchange rate of Lv 21 per US$ which is conservative. Details of the various activities which are assumed to be carried out each year on the plant are given in Annex 1, Attachment 1.

5.06 Demand Forecasts and System Loading. Three demand forecasts have been prepared in conjunction with NEK. These are a minimum, a medium and a maximum forecast presented in Table 3.2. These forecasts assume a comparatively constant system load factor over the forecast period of around 65%. This is comparable with the present load factor of 64%. The forecasts includes auxiliary consumption within the stations. Generation planning also requires a good representation of the system loading pattern and information has been collected from NEK of hourly loadings over the past 20 years. These values have been averaged on a normalized basis and monthly load duration curves derived. System demand is higher in the winter than in the summer due to heating loads, and the annual peak occurs in December. Detailed changes in these will undoubtedly occur as the consumer mix changes with the evolving economic situation.

5.07 Existing Generation Plants. The present generating plants in Bulgaria includes nuclear, conventional thermal stations, industrial cogeneration, combined district heating and power plants as well as hydro-electric stations. The present generating capability of this plant is 10,020 MW compared to the estimated 1993 peak demand of 6,840 MW (under the medium scenario). The installed capacity (1/1/93) is 12,080 MW made up of:

Hydro	-	1975.6 MW
Main thermal	-	4730.0 MW
Cogeneration	-	574.0 MW
Industrial	-	1040.2 MW
Nuclear	-	3760.0 MW

5.08 Detailed of these plants are given in Annex 5. Detailed plant data for the nuclear power units at Kozloduy are shown in the Annex 1, Attachment 1. The main fuels are locally mined lignite (primarily from the Maritza area), imported coal, natural gas and a limited quantity of fuel oil. Fuel details are also given in Annex 5. Present heat rates, O and M costs, and outage rates have been provided from information prepared by NEK in conjunction with the Bank. The heat rates are quoted on a gross generation basis and on a lower calorific value basis for the fuel. The co-generation and district heating plants have been modelled as composite plants for each fuel type and this is shown in Annex 5. Heat rates are for electricity production, not overall consumption. Data for the hydroelectric plants have been provided by NEK and the values of power and energy are given for three hydrological conditions having probabilities of 25%, 56% and 19% respectively. The retirement program was assured based on the age of the plant, and it is shown in Annex 5.

Table 5.2: Fixed System Summary of Dependable Capacities (MW)

	Hydroelectric	Thermal (MW)					Total
	(MW)	Fuel Type					
Year	Cap	Coal	Lignite	Foil	NGAS	Nuclear	
1993	1600	1940	1990	510	580	3400	10020
1994	2032	1940	1910	510	580	3400	9940
1995	2464	1915	1985	510	580	3400	9900
1996	2464	1915	1865	510	440	3400	9730
1997	2464	1750	1720	445	120	3400	9055
1998	2464	1750	1600	445	120	3400	8915
1999	2464	1555	1600	445	120	3400	8720
2000	2464	1165	1600	400	120	3400	8285
2004	2464	985	1607	400	120	3400	8105
2005	2464	625	1600	400	120	3000	7345
2008	2464	625	1600	400	120	2600	6945
2009	2464	430	1405	400	120	2600	6555
2010	2464	40	1210	400	120	2600	5970

5.08 Fuel Supplies. Fuel supplies are discussed in paras 4.05-4.25. For generation planning purposes it has been assumed that lignite will continue to be available at a cost of around US$1.06 per MMBTU. If major quantities of coal are to be imported then some new infrastructure will be required. Imported coal for Varna is priced at US$1.61/MMBTU and for Bobov Dol at about US$2/MMBTU. The fuel prices for imported fuels are based on world market prices, and in this study prices have been assumed to remain constant in real terms over the study period. Imported gas prices are based on a price of US$3.50/MMBTU at the Ukraine border, and 25 cents have been allowed for transit charges each through Romania and Ukraine giving a price to Bulgaria of US$4/MMBTU (US$12/Gcal). Nuclear fuel costs have been assumed constant in line with the assumptions outline in Section 3 above.

5.9 Generation Planning Criteria. The planning studies are being carried out over the period 1993 to 2010. The analysis has been carried out using monthly simulations for each of the three hydrological conditions, with the average results being adopted. A discount rate of 10% has been agreed for the study. No specific generation planning margin has been assumed, rather optimization studies have been carried out by incorporating a value for unserved energy of US$300/MWh. In practice the studies have indicated that this yields a planning margin of about 15%. The simulations have assumed that system spinning reserve will be provided by hydro plants and by imports, although in practice, the loss of a 1000 MW unit at Kozloduy cannot be covered fully and load shedding will be required. The studies have also assumed that the industrial and district heating plant must run. Although this is not strictly true for the district heating plants, WASP is unable to vary time of year availability of plant. Nuclear plant have not been forced to run, but care has been taken in analyzing the simulations to ensure that the nuclear units run at realistically high loading levels.

5.10 Expansion Planning. The need for generating capacity in the future can be met by rehabilitating or repowering existing plant or investing in new capacity.

(a) Rehabilitation and Repowering. Much of the industrial and district heating plant is elderly and makes poor use of fuel. Nevertheless, with modest expenditure it could be rehabilitated and given perhaps another 15 years life. Alternatively, better use could be made of fuel by repowering and converting to gas turbine prime movers with waste heat recovery for heat production. Estimates have been made of the potential for repowering and these indicate that very large increases in electricity generation are practicable for modest investment whilst still giving the same heat production. These possibilities are outlined in Annex 5 and 6, together with target investment dates, costs and performance improvements. If these repowering works are not carried out, then some refurbishment will be required at an estimated cost of US$250/kW, based on the existing capacity of the plants. For plants which are not explicitly indicated in these tables, then they have been assumed to be operational throughout the study, although in practice some works will be required, but it is beyond the scope of this study to fully analyze all these smaller plants. Refurbishment works are also desirable on the main power stations and are summarized in Annex 5.

(b) New Plant Candidates. New plant candidates have been included in the study. These include :

- 600 MW nuclear sets (for scenario 6 and low rehabilitation repowering option)
- 120 MW gas turbines
- 450 MW gas turbine combined cycle
- 500 MW imported coal steam sets
- new hydro stations
- 160 MW fluidized bed (low rehabilitation/repowering option)

The details and assumptions for the generation expansion studies for these new plants are included in Annex 5.

5.11 Comparison of the results of the screening curve analysis clearly shows that gas fired combined cycle plants are the most attractive new plant option, and that the repowering and rehabilitation options are particularly attractive when compared to new plant options. The rehabilitation and repowering options have therefore been given priority as investments during the 1990's particularly if capacity shortages are evident. These results were only used as initial information. The actual capacity addition (type, size and timing) were optional as a result of the optimization process with the least total system costs over the period 1993-2010 as an objective function.

Table 5.3: Capacity Additions for Different Load Forecasts and Scenarios

Year	MINIMUM						MEDIUM						MAXIMUM					
	0	1	2	3	4	5	0	1	2	3	4	5	0	1	2	3	6	4
1993	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0
1995	130	130	0	0	0	0	130	130	130	130	130	130	130	130	130	130	130	130
1996	[illegible]	[illegible]	0	0	0	0	1175	[illegible]	[illegible]	300	[illegible]	300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1997	[illegible]	0	150	0	0	0	450	[illegible]	130	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1998	[illegible]	[illegible]	219	[illegible]	165	150	[illegible]	[illegible]	1144	1144	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1999	[illegible]	[illegible]	[illegible]	[illegible]	0	0	[illegible]	[illegible]	360	360	360	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2000	316	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0
2001	210	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	210	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2002	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	370	370	370	370	0	[illegible]	0	[illegible]	0	0
2003	0	150	150	150	150	150	0	35	35	35	35	35	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]
2004	200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	200	200	200	200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]
2005	200	0	0	0	0	0	[illegible]	200	200	200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	[illegible]	[illegible]
2006	200	360	360	360	360	360	300	200	300	200	200	344	0	[illegible]	0	0	0	0
2007	0	1200	1200	1200	1200	1200	0	0	0	0	0		0	0	0	[illegible]	0	0
2008	0	0	0	0	0	0	0	0	0	0	0		[illegible]	0	0		0	0
2009	[illegible]	0	0	0	0	0	450	450	450	450	136	[illegible]	[illegible]	0	[illegible]		[illegible]	[illegible]
2010	[illegible]	0	0	0	0	0	900	570	570	570	900	[illegible]		[illegible]				
Total	5125	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5325	5325	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

5.12 In addition to the candidate plants described above, a commitment has been made to the Chaira pumped storage scheme. This comprises 4 units of 216 MW each. Two will be commissioned in 1993, and two in 1995. They have an efficiency of 75% and a potential for generating for 8.5 hours per day. This is equivalent to 1836 MWh per day per unit. This plant has been included in the fixed system for the purposes of the generation planning studies.

5.13 Imports. An alternative source of power and energy is imports from neighboring countries. As discussed elsewhere a number of options exist, and it was agreed that it should be assumed that 400 MW would be available as base load at a cost of US$0.035/kWh, roughly the current cost of imports. This was included as an option in the analysis.

B. Results

5.14 Capacity Balances. Available capacity under each nuclear scenario over the planning period has been compared with the demand forecasts assuming additional requirements to be met by the rehabilitation, repowering and construction of new generation plants. Rehabilitation of the main thermal plants, district heating and industrial plant rehabilitation/repowering were put on a footing of equality with the new construction and selection was made on the basis of the least total system cost. However, this approach assumes away organizational and institutional issues related to the fact that district heating and industrial plants are out of NEK's control though these issues can be overcome. The eighteen different cases were optimized over the period 1993-2010. Capacity additions for different load forecasts and scenarios are shown in Table 5.3. The present values of the objective function (total system costs) are shown in Table 5.4. These are the total costs of supplying electricity from 1993-2010 discounted at 10% for each case.

Table 5.4: Present Values of Least Total System Supply Costs for the 18 Cases
(US$ Billion in 1992)

Forecast\Scenario	Minimum	Medium	Maximum
0	9.556	12.025	12.795
1	6.221	8.201	9.148
2	6.055	7.401	8.848
3	5.891	7.668	8.633
4	5.556	7.115	7.851
5	5.486	6.939	7.561

5.15 The capacity balances, costs breakdown as well as planting schedules are given in Annex 5. The result shows that the system costs are more sensitive to the selection of the scenarios than the demand forecast (see Table 5.4). Under scenario 0, there is an immediate shortfall in capacity which can not be met by imports. This situation could be described in different ways. We believe that the most illustrative way are the number of days when the demand is not met for each of the eighteen considered options (Table 5.5).

Table 5.5: Number of Days when the demand is not met

	Minimum						Medium						Maximum					
Year	0	1	2	3	4	5	0	1	2	3	4	5	0	1	2	3	4	5
1993	29	1	1	1	1	1	29	1	1	1	1	1	29	1	1	1	1	1
1994	42	1	1	1	1	1	42	1	1	1	1	1	42	1	1	1	1	1
1995	72	1	1	1	1	1	72	1	1	1	1	1	72	1	1	1	1	1
1996	48	1	1	1	1	1	2	4	1	1	1	1	50	1	1	1	1	1
1997	1	1	1	1	1	1	17	2	1	1	1	1	1	1	1	1	1	1
1998	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1999	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2000	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2001	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2002	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2003	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2004	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2005	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2006	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2007	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2008	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2009	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2010	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

5.16 Energy Balances. In all cases analyzed, the most important contribution to the system generation comes from the nuclear plant generation, except scenarios 0 and 1. The energy generated by different generation sources are presented (for scenarios 1, 3 and 4) in Table 5.6 below.

TABLE - 5.6 ENERGY GENERATION BY PLANTS (GWh)

SCENERIO	TYPE	1993	% of TOT.	1994	% of TOT.	1995	% of TOT.	2000	% of TOT.	2005	% of TOT.	2010	% of TOT.
	MAXIMUM DEMAND FORECAST												
1	HYDRO	2445.12	6.3	2445.12	6.2	2445.12	5.9	3157.1	6.3	3157.1	5.8	5294.72	9.4
	THERMAL	23226.3	59.7	23968.4	61.0	26316.9	63.5	34359.6	68.4	37178.6	68.2	32210.21	56.9
	NUCLEAR	9752.06	25.1	9752.06	24.8	9752.06	23.5	9752.06	19.4	9752.07	17.9	9752.06	17.2
	DISTRICT	1227.87	3.2	717.06	1.8	813.32	2.0	981.15	2.0	906.36	1.7	1565.65	2.8
	INDUSTRY	2227.05	5.7	2425.62	6.2	2087.95	5.0	1962.49	3.9	3531.98	6.5	7757.85	13.7
	TOTAL	38878.4		39308.3		41415.4		50212.4		54526.1		56580.49	
3	HYDRO	2445.12	6.3	2445.12	6.2	2445.12	5.9	3157.1	6.3	3157.1	5.8	5294.72	9.4
	THERMAL	14906.4	38.3	15496.3	39.4	17529.3	42.3	34359.6	68.4	37178.6	68.2	32210.21	56.9
	NUCLEAR	21121.5	54.3	21139.3	53.8	21139.8	51.0	9752.06	19.4	9752.07	17.9	9752.06	17.2
	DISTRICT	223.14	0.6	59.82	0.2	90.72	0.2	981.15	2.0	906.36	1.7	1565.65	2.8
	INDUSTRY	189.35	0.5	171.7	0.4	214.56	0.5	1962.49	3.9	3531.98	6.5	7757.85	13.7
	TOTAL	38885.6		39312.3		41419.6		50212.4		54526.1		56580.49	
4	HYDRO	2445.12	6.3	2445.12	6.2	2445.12	5.9	3157.1	6.3	3157.1	5.8	3392.7	6.0
	THERMAL	14906.4	38.3	15496.3	39.4	17529.3	42.3	25147.0	50.1	30491.5	55.9	31823.76	56.2
	NUCLEAR	21121.5	54.3	21139.3	53.8	21139.8	51.0	15068.6	30.0	15068.6	27.6	15068.68	26.6
	DISTRICT	223.14	0.6	59.82	0.2	90.72	0.2	1074.59	2.1	943.93	1.7	1022.39	1.8
	INDUSTRY	189.35	0.5	171.7	0.4	214.56	0.5	5727.6	11.4	4857.85	8.9	5273.32	9.3
	TOTAL	38885.6		39312.3		41419.6		50173.0		54517.1		56578.83	
	MEDIUM DEMAND FORECAST												
1	HYDRO	2445.12	6.3	2445.12	6.2	2445.12	5.9	3157.1	6.8	3157.1	6.4	3392.7	6.5
	THERMAL	23226.3	59.7	23968.4	61.0	26316.9	63.5	28414.7	61.5	30715.7	62.4	32047.25	61.4
	NUCLEAR	9752.06	25.1	9752.06	24.8	9752.06	23.5	9752.06	21.1	9752.06	19.8	9752.06	18.7
	DISTRICT	1227.87	3.2	717.06	1.8	813.32	2.0	1064.18	2.3	998.62	2.0	1088.62	2.1
	INDUSTRY	2227.05	5.7	2425.62	6.2	2087.95	5.0	3819.41	8.3	4605.49	9.4	5905.5	11.3
	TOTAL	38878.4		39308.3		41415.4		46207.5		49226.9		52186.13	
3	HYDRO	2445.12	6.3	2445.12	6.2	2445.12	5.9	3157.1	6.8	3157.1	6.4	3392.7	6.5
	THERMAL	14906.4	38.3	15496.3	39.4	17529.3	42.3	28414.7	61.5	30715.7	62.4	32047.25	61.4
	NUCLEAR	21121.5	54.3	21139.3	53.8	21139.8	51.0	9752.06	21.1	9752.06	19.8	9752.06	18.7
	DISTRICT	223.14	0.6	59.82	0.2	90.72	0.2	1064.18	2.3	998.62	2.0	1088.62	2.1
	INDUSTRY	189.35	0.5	171.7	0.4	214.56	0.5	3819.41	8.3	4605.49	9.4	5905.5	11.3
	TOTAL	38885.6		39312.3		41419.6		46207.5		49226.9		52186.13	
4	HYDRO	2445.12	6.3	2445.12	6.2	2445.12	5.9	3157.1	6.8	3157.1	6.4	3157.1	6.0
	THERMAL	14906.4	38.3	15496.3	39.4	17529.3	42.3	24308.6	52.6	26784.1	54.4	28281.52	54.2
	NUCLEAR	21121.5	54.3	21139.3	53.8	21139.8	51.0	15068.6	32.6	15068.6	30.6	15068.68	28.9
	DISTRICT	223.14	0.6	59.82	0.2	90.72	0.2	984.48	2.1	830.83	1.7	945.69	1.8
	INDUSTRY	189.35	0.5	171.7	0.4	214.56	0.5	2694.35	5.8	3391.85	6.9	4727.76	9.1
	TOTAL	38885.6		39312.3		41419.6		46211.2		49230.4		52188.73	
	MINIMUM DEMAND FORECAST												
1	HYDRO	2445.12	6.8	2445.12	7.1	2445.12	7.3	2684.78	6.9	2684.78	6.6	3157.1	7.4
	THERMAL	21852	60.3	20884.5	60.8	20920.1	62.2	24002.4	62.1	26280.1	64.4	25062.94	58.9
	NUCLEAR	9752.06	26.9	9752.06	28.4	9752.06	29.0	9752.06	25.2	9752.06	23.9	9752.06	22.9
	DISTRICT	957.46	2.6	376.46	1.1	180.84	0.5	958.59	2.5	673.07	1.7	968.39	2.3
	INDUSTRY	1206.27	3.3	871.09	2.5	360.19	1.1	1260.91	3.3	1395.77	3.4	3604.6	8.5
	TOTAL	36212.9		34329.2		33658.3		38658.8		40785.8		42545.09	
3	HYDRO	2445.12	6.8	2445.12	7.1	2445.12	7.3	2684.78	6.9	2684.78	6.6	3157.1	7.4
	THERMAL	12480.8	34.5	10624.4	30.9	9970.71	29.6	24002.4	62.1	26280.1	64.4	25062.94	58.9
	NUCLEAR	21084.1	58.2	21111.2	61.5	21096.2	62.7	9752.06	25.2	9752.06	23.9	9752.06	22.9
	DISTRICT	55.11	0.2	1.31	0.0	1.21	0.0	958.59	2.5	673.07	1.7	968.39	2.3
	INDUSTRY	148.46	0.4	150.26	0.4	149.59	0.4	1260.91	3.3	1395.77	3.4	3604.6	8.5
	TOTAL	36213.6		34332.4		33661.8		38658.8		40785.8		42545.09	
4	HYDRO	2445.12	6.8	2445.12	7.1	2445.12	7.3	2445.12	6.3	2445.12	6.0	3157.1	7.4
	THERMAL	12480.8	34.5	10624.4	30.9	9970.71	29.6	20515.2	53.1	22997.8	56.4	21070.71	49.5
	NUCLEAR	21084.1	58.2	21111.2	61.5	21096.2	62.7	15068.6	39.0	15068.6	36.9	15068.68	35.4
	DISTRICT	55.11	0.2	1.31	0.0	1.21	0.0	568.57	1.5	196.09	0.5	744.84	1.8
	INDUSTRY	148.46	0.4	150.26	0.4	149.59	0.4	71.28	0.2	85.72	0.2	2507.11	5.9
	TOTAL	36213.6		34332.4		33661.8		38608.8		40791.4		42546.24	

TABLE – 5.7 FUEL REQUIREMENTS BY TYPE

SCENERIO	TYPE	UNITS	1993	1994	1995	2000	2005	2010
	MAXIMUM DEMAND FORECAST							
1	LIGNITE	(MILLION TON)	30.370	29.412	34.549	32.779	32.779	27.028
	COAL	(MILLION TON)	4.459	4.805	4.640	3.829	4.684	3.475
	NUCLEAR	(TON OF FUEL)	45.500	45.500	45.500	45.500	45.500	45.500
	N. GAS	(BILLION M**3)	0.143	0.145	0.105	2.463	2.662	3.553
	F. OIL	(MILLION TON)	0.085	0.098	0.090	0.000	0.000	0.000
3	LIGNITE	(MILLION TON)	25.531	26.443	29.614	32.779	32.779	27.028
	COAL	(MILLION TON)	1.232	1.231	1.371	3.829	4.684	3.475
	NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	45.500	45.500	45.500
	N. GAS	(BILLION M**3)	0.000	0.000	0.000	2.463	2.662	3.553
	F. OIL	(MILLION TON)	0.001	0.000	0.002	0.000	0.000	0.000
4	LIGNITE	(MILLION TON)	25.531	26.443	29.614	32.777	32.759	27.029
	COAL	(MILLION TON)	1.232	1.231	1.371	4.210	4.839	3.448
	NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	70.296	70.297	70.296
	N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.963	1.476	2.985
	F. OIL	(MILLION TON)	0.001	0.000	0.002	0.000	0.000	0.000
	MEDIUM DEMAND FORECAST							
1	LIGNITE	(MILLION TON)	30.370	29.412	34.549	32.781	32.774	27.028
	COAL	(MILLION TON)	4.459	4.805	4.640	4.149	4.697	3.460
	NUCLEAR	(TON OF FUEL)	45.500	45.500	45.500	45.500	45.500	45.500
	N. GAS	(BILLION M**3)	0.143	0.145	0.105	1.391	1.470	3.145
	F. OIL	(MILLION TON)	0.085	0.098	0.090	0.000	0.000	0.000
3	LIGNITE	(MILLION TON)	25.531	26.443	29.614	32.781	32.774	27.028
	COAL	(MILLION TON)	1.232	1.231	1.371	4.149	4.697	3.460
	NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	45.500	45.500	45.500
	N. GAS	(BILLION M**3)	0.000	0.000	0.000	1.391	1.470	3.145
	F. OIL	(MILLION TON)	0.001	0.000	0.002	0.000	0.000	0.000
4	LIGNITE	(MILLION TON)	25.531	26.443	29.614	32.697	32.656	27.022
	COAL	(MILLION TON)	1.232	1.231	1.371	3.809	4.356	3.433
	NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	70.296	70.298	70.298
	N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.477	0.599	2.161
	F. OIL	(MILLION TON)	0.001	0.000	0.002	0.000	0.000	0.000
	MINIMUM DEMAND FORECAST							
1	LIGNITE	(MILLION TON)	30.084	29.196	33.557	32.745	32.545	27.007
	COAL	(MILLION TON)	3.776	3.271	2.085	3.649	4.116	3.435
	NUCLEAR	(TON OF FUEL)	45.500	45.500	45.500	45.500	45.500	45.500
	N. GAS	(BILLION M**3)	0.039	0.003	0.000	0.222	0.246	1.304
	F. OIL	(MILLION TON)	0.064	0.054	0.010	0.000	0.000	0.000
3	LIGNITE	(MILLION TON)	22.935	21.039	19.704	32.745	32.545	27.007
	COAL	(MILLION TON)	0.627	0.177	0.086	3.649	4.116	3.435
	NUCLEAR	(TON OF FUEL)	98.372	98.499	98.424	45.500	45.500	45.500
	N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.222	0.246	1.304
	F. OIL	(MILLION TON)	0.000	0.000	0.000	0.000	0.000	0.000
4	LIGNITE	(MILLION TON)	22.935	21.039	19.704	31.229	30.488	26.484
	COAL	(MILLION TON)	0.627	0.177	0.086	2.259	3.008	3.136
	NUCLEAR	(TON OF FUEL)	98.372	98.499	98.424	70.297	70.298	70.297
	N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.012	0.015	0.444
	F. OIL	(MILLION TON)	0.000	0.000	0.000	0.000	0.000	0.000

5.18 Fuel Requirements. The reability and diversity of the fuel supply to the Bulgarian power sector is one of the most important issue to be considered for both operational and long-term planning purposes. Immediate supply is relevant to the emergency measures during the winter months. The long-term fuel policy is a crucial issue from the economic point of view. For the three scenarios (1, 3 and 4) the fuel requirements over the period 1993-2010 are presented in Table 5.7.

5.19 Summary. The eighteen different cases have been analyzed. Scenario 6 was dropped from the further consideration when it was found that it is not different from scenario 5. The present values of the least total system costs presented in Table 5.4 clearly indicate three groups of scenarios: (a) group A (scenario 0); (b) group B (scenarios 1, 2 and 3); and (c) group C (scenarios 4 and 5).

Group A - Scenario 0 is the substantially more expensive solution than any other. In addition to that, the system parameters presented in Table 5.5 indicates that this is not a feasible solution.

Group B - Scenarios 1, 2 and 3 which assume shut-down of Kozloduy units 1-4 in 1993 to 1998 are very similar from the point of view of total costs. The difference between the lowest and highest values for different load forecasts is within 5 to 7%.

Group C - Scenarios 4 and 5 show practically no difference and are lower in cost than the scenarios in groups A and B.

5.20 The lowest total system cost is scenario 5, which includes the safety improvements of all Kozloduy units and their operation through to end of their design life. This report did not analyze the adequacy of the nuclear safety improvements and related cost estimates. However, it is useful to underline moderate incremental system costs for the scenarios 1, 2 and 3 and relative to the cost of scenario 5 costs. The incremental costs are given in Table 5.8. (For example Table 5.8 shows that the present value discounted at 100% of the incremental costs of scenario 1 relative to scenario 5 in the minimum demand case are US$735 billion). The breakdown of the system cost is given in Table 5.9.

Table 5.8: Present Value of Incremental System Costs
(US$ Billions, 1992 dollars)

Scenario	Minimum	%	Medium	%	Maximum	%
0	4.070	73.8	5.086	73.3	5.234	69.2
1	0.735	13.4	1.262	18.2	1.587	20.9
2	0.569	10.4	1.042	16.4	1.287	17.0
3	0.405	7.4	0.729	10.5	1.072	14.0
4	0.050	0.9	0.176	2.5	0.290	3.8

Table 5.9: Costs of System's Electricity Supply
(US$ millions, 1992 dollars)

Nuclear Scenario	Demand Forecast	Nuclear Safety Upgrade	Fuel	O&M	Non-nuclear Investment	Total
Low Nuclear (scenario 1)	Minimum	678	7,451	2,969	1,372	12,470
	Medium	678	9,963	3,708	2,137	16,487
	Maximum	678	10,846	3,933	2,861	18,320
Moderate Nuclear (scenario 3)	Minimum	914	6,936	2,894	1,372	12,116
	Medium	914	9,374	3,574	2,138	16,000
	Maximum	914	10,224	3,759	2,861	17,759
High Nuclear (scenario 4)	Minimum	1,210	6,187	2,602	1,045	11,044
	Medium	1,210	8,478	3,314	1,698	14,701
	Maximum	1,210	9,571	3,666	2,137	16,586

5.21 In summary, the analysis of the Bulgarian electricity system shows that Scenario 0, which involves shutting all 6 units at Kozloduy, is infeasible since it involves very high costs and a large unsatisfied electricity demand. However the other five scenarios which involve closing units 1-4 at various dates or keeping all units running through the end of their demand life are potentially feasible though with different costs. The longer units 1-4 are run, the lower are the total costs of supplying electricity with scenario 5, which involves running all units to the end of their design life after safety upgrades, being the lowest cost of all. In choosing between scenarios 1-5, the Bulgarian authorities must primarily consider three factors: 1) nuclear safety; 2) costs; and 3) the availability of non-nuclear fuels especially natural gas for which there is a single supplier. The choice between the scenarios is largely a matter of trade offs. Increasing nuclear safety raises costs and the risks involved in increasing dependance on imported non-nuclear fuels. However, the analysis does indicate that the costs of increasing nuclear safety by shutting the older units at Kozloduy are not enormous.

5.22 Low Rehabilitation/Repowering Option (Limited Gas Usage). The Bulgarian Government was concerned that the results of the analysis discussed above relied too much on repowering industrial and district heating plants using gas fired combined cycle units. They were concerned that this repowering might be more expensive than anticipated and in any case would increase reliance on imported gas. Therefore, at the request of the Bulgarian Government, additional cases where run where the repowering of the industrial generation plants is substantially limited in comparison with the already analyzed. Also additions to the gas-fired plants (combined cycle) were limited to about 600 MW and total gas usage for electricity and heat was limited to about 2 BM^3. This approach lead to present values of total system costs which are not substantially different (3-8% higher) than for equivalent cases with the high repowering program, but the expenditures structure is different. The repowering option has lower investment cost in the next 5-6 years, and higher fuel cost while the other option involves higher investment cost in the medium-term and its financial feasibility is questionable. The present value of incremental system cost as well as the cost breakdown for this option are presented in Tables 5.10, 5,11 and 5.12.

Table 5.10: Present Values of Total System Costs for the 18 Cases with Limited Gas Usage (US$ Billion)

	Demand Forecast		
Scenario	Minimum	Medium	Maximum
0	8.273	10.294	12.691
1	6.180	8.666	9.747
2	6.018	8.356	9.371
3	5.853	8.061	9.146
4	5.334	7.240	8.188
5	5.294	6.903	7.763

Table 5.11: Incremental System Costs Relative to Full Gas Usage

	Minimum	%	Medium	%	Maximum	%
0	2.979	56.3	3.391	49.1	4.928	63.5
1	0.886	16.7	1.763	25.5	1.984	25.5
2	0.724	13.7	1.453	21.0	1.608	20.7
3	0.559	10.5	1.158	11.8	1.383	17.8
4	0.040	0.7	0.337	4.9	0.425	5.5

Table 5.12: Costs of System's Electricity Supply with Limits on Gas Usage (US$ millions, 1992 dollars)

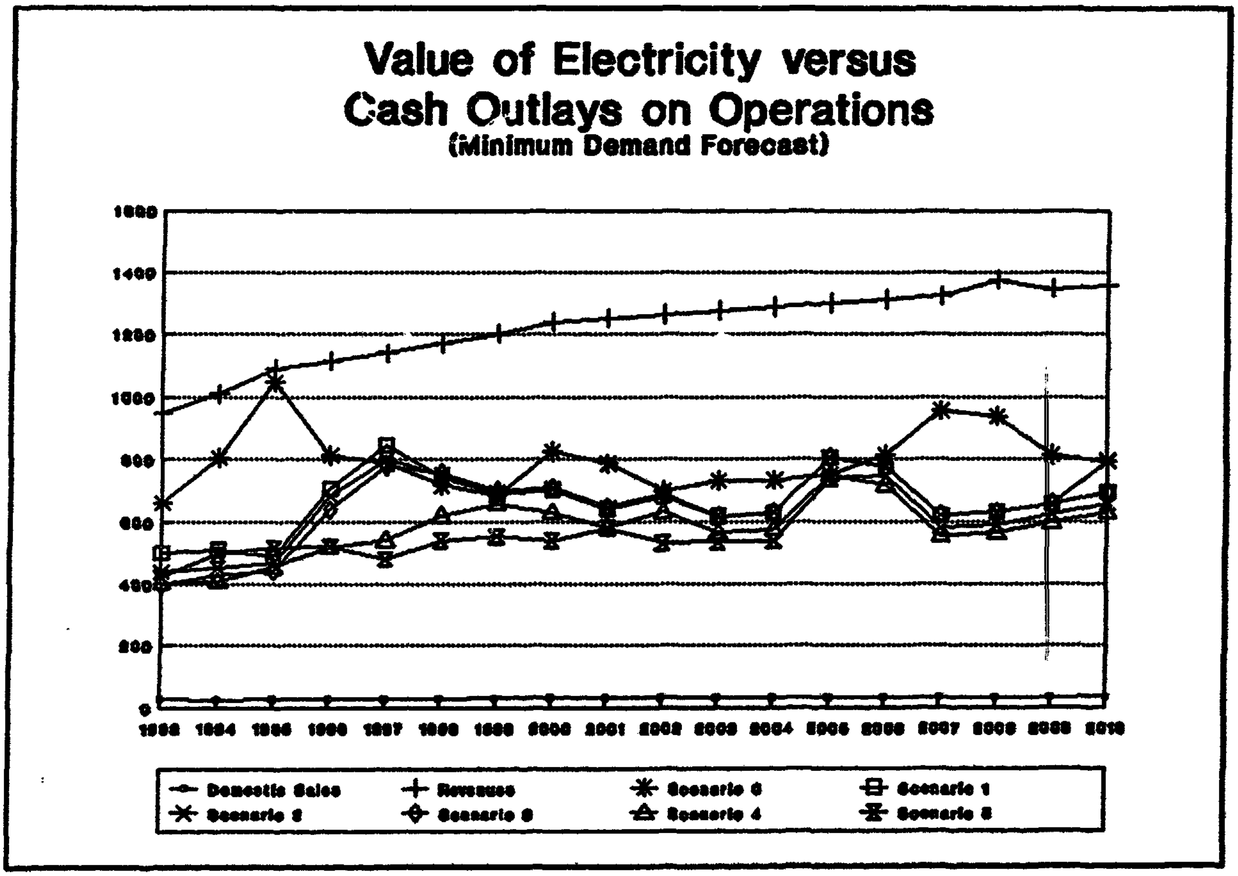
Nuclear Scenario	Demand Forecast	Nuclear Safety Upgrade	Fuel	O&M	Non-nuclear Investment	Total
Low Nuclear (scenario 1)	Minimum	678	7,189	3,106	1,860	12,834
	Medium	678	9,264	3,924	3,392	17,259
	Maximum	678	10,113	4,325	4,596	19,712
Moderate Nuclear (scenario 3)	Minimum	914	6,666	3,030	1,860	12,471
	Medium	914	8,649	3,705	3,389	16,659
	Maximum	914	9,517	4,118	4,596	19,146
High Nuclear (scenario 4)	Minimum	1,210	6,138	2,735	949	11,033
	Medium	1,210	8,025	3,412	2,411	15,059
	Maximum	1,210	9,035	3,681	3,391	17,318

5.24 Transmission System. The least cost scenarios envisage no major additions to the transmission stock. Kozloduy is mostly envisaged operating with at least 4 units, and in the next ten years any additional capacity is likely to be repowering of cogeneration. Such repowering is within the low voltage system and since these schemes are near to load centers, it is unlikely that any major transmission extensions will be required. This study has not analyzed the low voltage network, but as far as the high voltage system is concerned, no major reinforcements over and above those planned by NEK seem necessary.

C. Financial Aspects

5.25 To get a rough indication of whether the capital investments and operating costs forecast above are financially feasible the value of final electricity consumption in Bulgaria was forecast for the three demand cases. Final electricity consumption consists of sales of electricity by the National Electric company (NEK) and cogenerators own use of electricity. The electricity was valued at an average price of 3.7 US cents/kWh. This would be the average sales price for NEK and was assumed for the sake of simplicity to be the value cogenerators would also put on their own consumption of electricity. This price is slightly above the average price that NEK has agreed with the Bank to attain by September 1, 1993 (3.5 US cents/kWh), since NEK has agreed that starting in late 1994 its average sales price of electricity should be the higher of: (a) the long run marginal cost of electricity supply; or (b) that price required for NEK to meet certain financial covenants specified by the Bank. While this price is not yet known, it is estimated to be in the 3.5-4.0 US cents/kWh range.

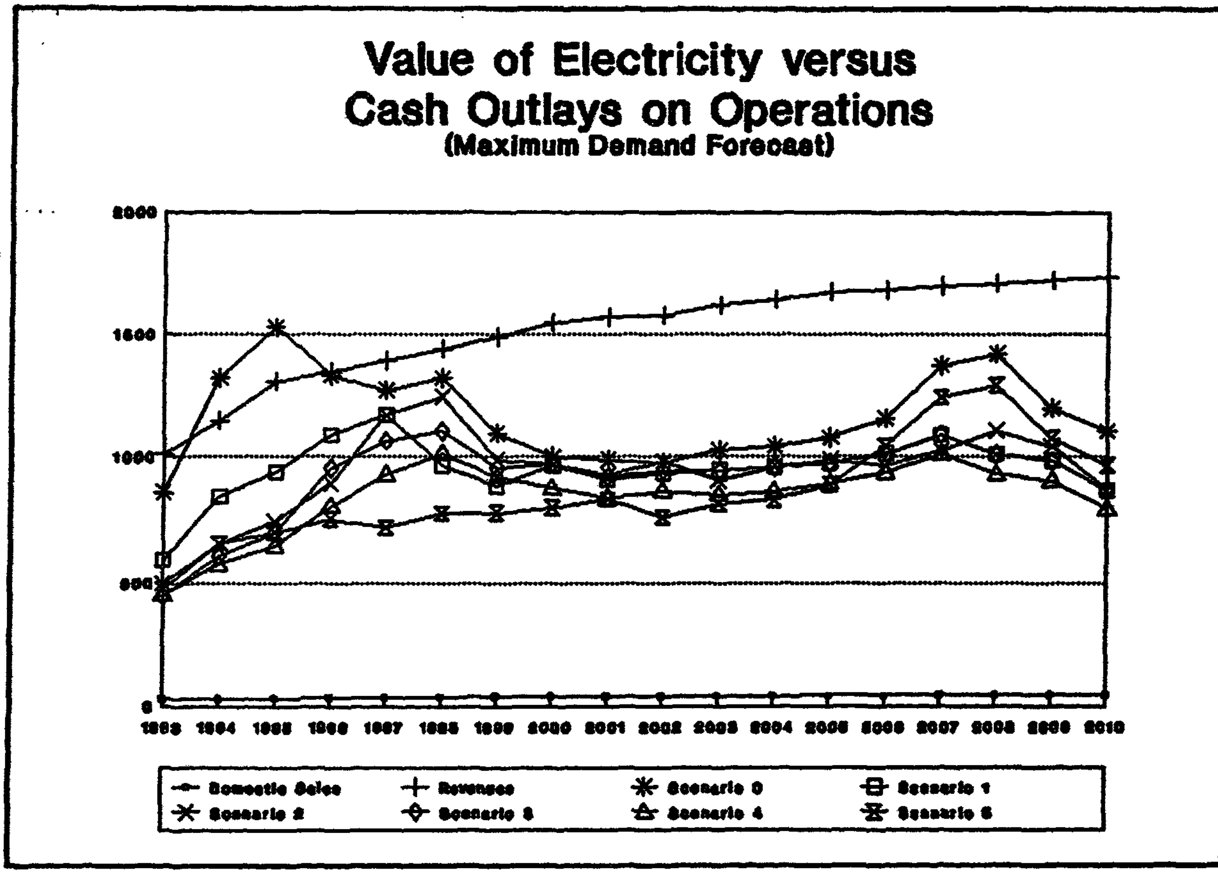
Figure 5.13



5.26 Figure 5.13 shows the value of final electricity consumption in the minimum demand case from 1993 to 2010 (top line), compared with the total cash operating and investment costs (cash outlays) for each year for each scenario (bottom lines). These cash outlays consist of all fuel costs, operating and maintenance costs and capital outlays. They exclude income taxes, dividends, levies in lieu of dividends, and debt service. They also exclude some investments which are underway such as the completion of unit 8 at the Maritza East II plant and the Bank's project with NEK which will involve it in some local capital outlays. Foreign debt service and the required capital outlays under the ongoing projects together, however, would be less than US$50 million per year.

5.27 Figure 5.13 shows that with the minimum demand forecast and a tariff of 3.7 US cents/kWh; NEK would potentially be in a relatively strong financial position and able to finance operating costs and most of the required capital investments under nuclear scenarios 1 to 5 assuming that taxes and other levies on it were limited. Scenario 0, with the immediate closure of all nuclear plants, would be harder to finance. Also as pointed out above, this scenario is infeasible since it would result in massive electricity shortages in the shorter term and severely damage the economy.

Figure 5.14



5.28 Figure 5.14 shows the same situation for the maximum demand forecast. Given this forecast of demand, scenario 0 would be very difficult to finance even excluding the major damage that closure of all of the nuclear units under this scenario would have on the economy. The situation with the medium demand forecast is roughly half way between the maximum and minimum demand forecasts.

5.29 The above analysis is rough and could be refined. However, it does indicate that at expected levels of electricity tariffs and with a reasonable taxation burden, NEK and the cogenerators may be able to finance most of the costs of scenarios 1 to 5 under all demand cases. Scenario 0 would be

BULGARIA

NUCLEAR POWER PLANTS

1. Background. The only nuclear plant in Bulgaria is owned by NEK and is situated at Kozloduy, about 220 km north of Sofia on the Danube river. It comprises 4x440 MW and 2x1000 MW units with a total installed capacity of 3,760 MW. All units are pressurized water reactors (PWR) utilizing slightly enriched uranium as fuel and common water as moderator and coolant. The four 440 MW units -- units 1, 2, 3 and 4 -- were commissioned in the years 1974, 1975, 1980, and 1982 respectively. Unit 5 (VVER-1000) was commissioned in December 1988. Unit 6 is operating at partial output, but as of early 1993, the Committee for the Peaceful Uses of Atomic Energy, the Bulgarian nuclear regulatory agency, had not yet allowed it to attain full power and it has not been officially commissioned.

2. The performance of units 1-4 over the past few years has been quite good: for example, the average plant load factor for units 1-4 was 76.0% in 1988, and 71.2% in 1989. The performance of unit 5 over the quite limited time period in which it has been operating has not been as good, due largely to initial problems with the steam generators. The Kozloduy plant is being used as a baseload plant and has a good record of unplanned reactor scrams (2-3 per reactor per year).

3. The Kozloduy units 1 to 4 are of the early VVER-440/V230 design, developed by the Soviets in the 1960s and 1970s. Along with other units of the same type,[1] they have been the focus of international concern during the past years. In addition, a number of managerial, training and material problems exist at these units. While the VVER-1000 units do not have the same design deficiencies as the VVER-440's, they have instrumentation and control deficiencies, steam generator problems and suffer from many of the same managerial, training and material problems as the VVER-440 units.

4. The COE had planned for a second nuclear power site on the Danube at Belene, consisting of two VVER-1000 units in phase 1 and two additional units in phase 2. A considerable amount of equipment was ordered and paid for which was to be used for unit 1 and some construction at the site has taken place. However, in view of: 1) the drastic political changes which have occurred in the country, 2) safety concerns about nuclear power, and 3) the major economic changes which are ongoing in the country and will result in lower electricity demand, the Government of Bulgaria stopped construction of the Belene plant. The Bank strongly supports this position.

5. Safety Concerns about Design of VVER-440's/IAEA safety review. As a result of international concern about the safety of the design of the VVER-440, model V230, the International Atomic Energy Agency (IAEA), at the urging of its members, organized a concerted effort to perform a comprehensive review of the problem and to make appropriate recommendations. This effort, initiated in 1989 as an extra-budgetary activity of the Agency, consisted of the following components:

(a) a generic design review, performed in February 1991,

(b) site visits and evaluations, and

(c) a comprehensive report presenting conclusions and recommendations in December 1991.

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[1] In addition to the Kozloduy units 1-4, the following units of the same type are still in operation: at Bohunice, Czechoslovakia 2 units; at Novovoronezh, Russia, 2 units; and at Kola, Russia, 4 units. The three units at Greifswald, Germany and the two units in Armenia, have been shut down.

6. The generic review process of the Agency, with the cooperation of the Soviet designers, concluded (as anticipated) that the design of the VVER-440 model 230 lacks many important safety features considered mandatory by commonly accepted international practice. These include lack of: redundant systems for high-pressure injection of coolant in case of a large pipe break in the system, backup feedwater circuits, and a full-scale containment structure that can withstand a substantial overpressure resulting from an accident. In particular, the review determined that the design lacks three important properties considered essential in international practice i.e., redundancy, diversity, and segregation of safety systems. This lack makes the safety systems particularly vulnerable to simultaneous failure caused by the same cause or mode. The system layout gives poor protection against internal and external hazards like fires, floods, earthquakes etc. The original plant design was applied initially exclusively to low-seismicity sites in accordance to Soviet regulation. (Unfortunately, this assumption does not apply at Kozloduy, though the plant is not in a particularly high seismicity Zone by Bulgarian standards.) Heavy reliance was also placed on operator control which increases the need for skilled operators and raises the probability of human error.

7. On the other hand, the IAEA review also recognized that the design of the units has certain redeeming features. The design was quite conservative, providing large thermal margins, sturdy fuel design, a large volume of water above the reactor core, and very large steam generators with large amounts of water for heat removal which would last for several hours even without active circulation. However, these conservative features, although providing considerable credit in any safety evaluation, are accepted not be able to mitigate against a large pipe break of the primary circuit or other severe accident scenarios.

8. The IAEA review recognized that there exist significant differences in the details of the design among the various plants of the same general design, owing to variations in the actual design used, site characteristics, or to later backfitting measures. However, these differences are generally not major and have a secondary impact on safety. In addition to the design deficiencies identified, it is generally recognized that there are other and in some ways more important safety problems at some of these plants including: 1) deficiencies in the quality of materials; 2) lack of quality assurance during construction; 3) poor instrumentation and control design and operation; 4) poor operator training; 5) inadequate maintenance procedures; and 6) inadequate management structure.

9. The IAEA review also identified a number of investments which would be needed in most of the VVER-440 plants. These investments were classified into three categories:

Category I: Immediate need.
Category II: Within two years.
Category III: Longer than two years.

In Category I, the following needs were identified:

(a) leak detection devices in the primary circuit to allow shutdown before a catastrophic failure (because this model has only a limited capacity for emergency coolant injection in the case of a large break);

(b) upgrading of instrumentation and control systems, including power controller, control room instruments, miscellaneous detectors, and operator aids.

In Category II, the following items were included:

(a) simulators for operator training;
(b) auxiliary and emergency feedwater systems;
(c) improved fire protection;
(d) thermal hydraulic analyses;
(e) probabilistic safety analyses, level I (i.e., to the probability of core meltdown); (this item includes information of categories I, II, and III).

In Category III, the following were included:

(a) upgrading of steam generator systems performance;
(b) confinement system evaluation and possible upgrading.

10. After much of the work on the generic review had taken place, a specific site visit was carried out by an IAEA team at Kozloduy in June 1991. The team found that, in addition to the expected design deficiencies, operational practices and material conditions of the plant were very poor. Safety equipment had been allowed to deteriorate, fire hazards existed, morale was very poor, personnel were not adequately trained or led and management was demoralized with little authority to act.

11. Emergency improvement program for Kozloduy. The international concern created by the IAEA's review of the VVER-440 model 230 reactors and specifically its report on Kozloduy culminated in a meeting in Vienna on July 9, 1991 at which international emergency assistance was decided for Kozloduy. The Commission of the European Communities (CEC) was designated as the focus of this effort and was asked to coordinate, finance and administer the emergency program. The CEC allocated 11.5 million ECU for this purpose. The program has five components and is primarily implemented by the World Association of Nuclear Operators (WANO). The components are:

(a) Urgent Housekeeping Program, is executed by a team of about 15 foreign personnel experienced in power plant operations, and covering urgently needed actions to correct the material conditions at units 1-4 in Kozloduy that were identified by the IAEA Safety Review Mission in June, 1991.

(b) Twinning Arrangement, is primarily implemented by foreign personnel from the nuclear power plants at Bugey (France) to improve management and organization, safety culture, staff professionalism, operational and maintenance methodologies, quality assurance (QA) programs, and supervision of implementation of agreed actions.

(c) Six-Month Safety Assessment and Improvement Program is implemented by expert personnel from Europe and to a lesser degree the US. This program is for the urgent resolution of basic safety issues such as reactor pressure vessel and primary circuit integrity, accident analysis, confinement leak tightness, simulator training, and anti-seismic measures. It includes the initiation but not the completion of the very important task of writing new procedures for normal and emergency operations.

(d) Technical Assistance to the Committee on the Peaceful Uses of Atomic Energy (the Bulgarian Nuclear Regulatory Authority) by European nuclear regulatory experts. The Committee is receiving guidance on strengthening and extending its capability in establishing standards, monitoring compliance at the plant, and enforcing the regulations in every aspect of plant operations.

(e) A Study of Bulgaria's Electricity situation in the short run was undertaken by Eurelectric, a consortium of European Electric Power Companies and has been completed.

While this program is designed as a short run effort to improve the condition of the Kozloduy plant, it will continue in some form over a longer period given the deep-seated nature of some of Kozloduy's problems.

12. As a result in part of the IAEA report on Kozloduy and the Vienna meeting, the Bulgarian authorities agreed to take corrective measures in a phased program, first to upgrade unit 4 followed by unit 3 and, when work on these two units was completed, to perform the upgrading of units 1 and 2. This is in the process of being carried out.

13. Status of the VVER-1000's, Units 5 and 6. Although these units are of a later vintage, better designed, and are equipped with the necessary redundant safety systems required by western standards, including a full containment structure, they have material problems in the horizontal steam generators where cracks have developed in certain cases. Work on the steam generators, consisting of repair and heat treatment followed by inspection, have been completed for both units and it is thought this will prevent the future occurrence of cracks. It is also known that the instrumentation and control systems are not up to modern standards and it has been reported that reactor core presents stability problems which may interfere with the economic and stable operation of the units.

14. An IAEA Operational Safety Assessment Review Team (OSART) has reviewed units 5 and 6 and confirmed that the main deficiencies are not in the design area but rather are in the areas of management, personnel training, adequate incentives for performance, operating procedures, and regulatory measures. Perhaps the single most important area, which affected all the units at Kozloduy, was the salaries paid to skilled workers, i.e. shift supervisors and licensed control room operators, and to managers. These were quite low, but have very recently been sharply increased. Nevertheless, there remain very poor social and living conditions in the town of Kozloduy. Attached as Appendix 1 to this annex are the details of the six nuclear scenarios.

BULGARIA

NUCLEAR POWER PLANT SCENARIOS

1.1 The six different nuclear scenarios have been prepared by NEK and they are presented in this Annex.

1.2 The basic technical data describing the Kozloduy 1 - 6 units are also presented in the form as they have been given to the Mission by NEK.

1.3 Presented below are the six nuclear operating scenarios that are to be considered for the future of the nuclear industry in Bulgaria.

SCENARIO 0 -	**All 6 units at Kozloduy cease power production immediately no future nuclear developments.**
1.1.93	All 6 units cease power production
1.1.93-1.1.98	All 6 units will be operated in the shutdown state (this will require development of specific safety plans). Continual upgrade of plant to ensure safety in the shutdown state.
1.1.93	Commence decommissioning studies and develop plan.
1.1.98	Implement decommissioning plan.
SCENARIO 1 -	**Kozloduy units 1 to 4 cease power production 31.12.92, Kozloduy units 5 and 6 continued operation through to design end of life.**
1.1.93	Units 1 to 4 cease power production.
1.1.93-1.1.98	Units 1 to 4 will be operated in the shutdown state (this will require development of specific safety plans). Continual upgrade of Units 1 to 4 to ensure safety in the shutdown state.
1.1.93	Commence decommissioning studies and develop plan for Units 1 to 4.
1.1.98	Implement decommissioning plan on Units 1 to 4.
1.1.93-1.1.95	Perform safety and availability studies for Units 5 and 6.
1.1.96-1.1.97	Carry out research and development, design and procurement of the safety/availability features identified by the above study.
1.1.97-1.1.99	The above features will be installed (this may result in a reduced availability of the units).

1.1.99-DEOL	Continued safety and operational upgrades will be made to Units 5 and 6 on an annual basis.
SCENARIO 2 -	**Kozloduy Units 1 and 2 cease power production immediately. Units 3 and 4 cease power production on 1.1.1.98, Units 5 and 6 continued operation through to design end of life.**
1.1.93	Units 1 and 2 cease power production.
1.1.93-1.1.98	Units 1 and 2 will be operated in the shutdown state (this will require development of specific safety plans). Continual upgrade of Units 1 and to 2 to ensure safety in the shutdown state.
1.1.93	Commence decommissioning studies and develop plan for Units 1 and 2.
1.1.98	Implement decommissioning plan on Units 1 and 2.
1.1.93-1.1.96	Short-term safety upgrades of Units 3 and 4.
1.1.96-1.1.98	Continued safety and operational upgrades will be made to Units 3 and 4.
1.1.97-1.1.98	Develop shutdown plan for Units 3 and 4.
1.1.98	Units 3 and 4 cease power production.
1.1.98-1.1.03	Units 3 and 4 will be operated in the shutdown state. Continual upgrade of Units 3 and 4 to ensure safety in the shutdown state.
1.1.98	Commence decommissioning studies and develop plan for Units 3 and 4.
1.1.03	Implement decommissioning plan on Units 3 and 4.
1.1.93-1.1.95	Perform safety and availability studies for Units 5 and 6.
1.1.96-1.1.97	Carry out research and development, design and procurement of the safety/availability features identified by the above study.
1.1.97-1.1.99	The above features will be installed (this may result in a reduced availability of the units).
1.1.99-DEOL	Continued safety and operational upgrades will be made to Units 5 and 6 on an annual basis.

SCENARIO 3 -	**Kozloduy Units 1 and 2 cease power production in 1998, Units 3 to 6 continued operation through to design end of life.**
1.1.93-1.1.96	Short-term safety upgrades of Units 1 to 4.
1.1.93-1.1.94	Carry out research and development, design and procurement of the safety/availability features identified by previous studies for Units 3 and 4.
1.1.96-1.1.97	The above features will be installed on Units 3 and 4 (this may result in a reduced availability of the units).
1.1.96-DEOL	Continued safety and operational upgrades will be made of Units 3 and 4 on an annual basis.
1.1.96-1.1.98	Continued safety upgrades will be made to Units 1 and 2.
1.1.97-1.1.98	Develop shutdown plan for Units 1 and 2.
1.1.98	Units 1 and 2 cease power production.
1.1.98-1.1.03	Units 1 and 2 will be operated in the shutdown state. Continual upgrade of Units 1 and 2 to ensure safety in the shutdown state.
1.1.98	Commence decommissioning studies and develop plan for Units 1 and 2.
1.1.03	Implement decommissioning plan on Units 1 and 2.
1.1.93-1.1.95	Perform safety and availability studies for Units 5 and 6.
1.1.96-1.1.97	Carry out research and development, design and procurement of the safety/availability features identified by the above study.
1.1.97-1.1.99	The above features will be installed (this may result in a reduced availability of the units).
1.1.99-DEOL	Continued safety and operational upgrades will be made of Units 5 and 6 on an annual basis.
SCENARIO 4 -	**All 6 Kozloduy Units operation through to design end of life.**
1.1.93-1.1.96	Short-term safety upgrades of Units 1 to 4.
1.1.93-1.1.94	Carry out research and development, design and procurement of the safety/availability features identified by previous studies for Units 1 to 4.

1.1.96-1.1.99	**The above features will be installed on Units 1 to 4 (this may result in a reduced availability of the units).**
1.1.99-DEOL	**Continued safety and operational upgrades will be made to Units 1 to 4 on an annual basis.**
1.1.03-1.1.04	**Develop shutdown plan for Units 1 and 2.**
1.1.04	**Units 1 and 2 cease power production.**
1.1.04-1.1.09	**Units 1 and 2 will be operated in the shutdown state.** **Continual upgrade of Units 1 and 2 to ensure safety in the shutdown state.**
1.1.04	**Commence decommissioning studies and develop plan for Units 1 and 2.**
1.1.09	**Implement decommissioning plan on Units 1 and 2.**
1.1.09-1.1.10	**Develop shutdown plan for Units 3 and 4.**
1.1.10	**Units 3 and 4 cease power production.**
1.1.10-1.1.15	**Units 3 and 4 will be operated in the shutdown state.** **Continual upgrade of Units 3 and 4 to ensure safety in the shutdown state.**
1.1.10	**Commence decommissioning studies and develop plan for Units 3 and 4.**
1.1.15	**Implement decommissioning plan on Units 3 and 4.**
1.1.93-1.1.95	**Perform safety and availability studies for Units 5 and 6.**
1.1.96-1.1.97	**Carry out research and development, design and procurement of the safety/availability features identified by the above study.**
1.1.97-1.1.99	**The above features will be installed (this may result in a reduced availability of the units).**
1.1.99-DEOL	**Continued safety and operational upgrades will be made to Units 5 and 6 on an annual basis.**

SCENARIO 5 - All Kozloduy Units operation through to design end of life and new nuclear construction if deemed to be required by electricity demand.

This is the same as Scenario 4, with the consideration of future construction of additional units. The number and capacities of new units will depend on the demand forecasts. As such construction costs should be quoted in terms of cost per MW constructed. These should be total costs including design, analysis, procurement, construction, commissioning, etc.

COMMENTS:

1. Design end of life (DEOL) is considered to be 30 years from commencement of commercial operations.

2. For ease of analysis it is proposed that Units 1 and 2 should be simultaneously shut down, similarly for Units 3 and 4.

Nuclear Safety/Upgrade Investment Costs (US$M)

	SCENARIO					
Year	0	1	2	3	4	5
1993	23.3	35.0	47.5	60.0	65.0	85.6
1994	16.3	30.0	54.3	78.1	63.1	150.6
1995	11.7	37.5	62.3	88.1	128.1	190.0
1996	11.7	07.5	113.8	130.0	160.0	165.0
1997	11.7	117.0	133.8	150.0	150.0	90.0
1998	0.0	50.0	57.5	65.0	77.5	75.0
1999	0.0	35.0	40.3	45.5	60.3	60.0
2000	0.0	20.0	23.8	27.5	43.8	60.0
2001	0.0	20.0	23.8	27.5	43.8	115.0
2002	0.0	75.0	78.8	82.5	98.8	60.0
2003	0.0	20.0	20.0	20.0	40.0	67.5
2004	0.0	20.0	20.0	20.0	40.0	65.3
2005	0.0	20.0	20.0	20.0	40.0	63.8
2006	0.0	20.0	20.0	20.0	40.0	63.8
2007	0.0	20.0	20.0	20.0	40.0	63.8
2008	0.0	20.0	20.0	20.0	40.0	63.8
2009	0.0	20.0	20.0	20.0	40.0	63.8
2010	0.0	20.0	20.0	20.0	40.0	63.8

BG - 1 KOZLODUY -1

Current status:	OPERATIONAL
I. GENERAL	
Station name	Kozloduy - 1
Region of Township	Kozloduy
Station Coordinates:	
Latitude (degrees, minutes):	
Longitude (degrees, minutes):	
Reactor Type:	PWR
Reactor System Supplier:	ATOMENERGOEXPORT
Turbine Generator Supplier:	ATOMENERGOEXPORT
Owner(s):	NATIONAL ELECTRIC COMPANY
Operator:	KOZLODUY NPP
II. MAILING ADDRESS:	
Station Address:	NPS Kozloduy 3320 Kozloduy Bulgaria
Station Telephone	(02)871312, (0973)71
Telex	33 416
Fax	(0973) 2591
Utility Address:	NEK 8 Triaditza Str 1000 Sofia Bulgaria
Utility Telephone:	(02)86191
Telex	22707, 22708
Fax	(02) 875826

III. OUTPUT PER REACTOR UNIT:

	Design	Current
Nuclear thermal:	1375	1375
Gross electrical	440	440
Net electrical	408	408

IV. DATE OF:

State of Construction	April 1970
First critically	June 30, 1974
First synchronization to grid	August 14, 1974
Commercial Operation	October 25, 1974

V. REACTOR CORE CHARACTERISTICS

Fuel material:	UO_2
No of fuel assemblies	349
No of fuel rods per assembly	126
Av. initial fuel enrichment	2.5 (w%)
Av. reload fuel enrichment:	3.6 (w%)
Cladding, material:	ZR
thickness:	0.65 (mm)
Fuel loading:	42 (tonne U)
Power density in fuel:	32 (kW/kg U)
Power density in core:	84.2 (kW/lit)
Linear power density:	12.5 (kW/m)
Discharge burnup, design av.	28600 (MWd/t)
Method of refuelling	off load
- design frequency of refuelling	12 (months)
- part of core withdrawn	33 (%)
Means of reactivity control:	H_3BO_3

VI. PLANT SYSTEMS

Reactor vessel, basic material:	LOW ALLOY STEEL
cladding material:	NO CLADDING
Primary system description:	
No. of primary pumps	6
Coolant: Material:	H_20
Mass flow through core:	39000 (t/h)
Outlet temperature:	298 (deg C)
Outlet pressure:	125 (kg/cm^2)
Steam generator(s): Number:	6
Type:	PGW-4E
Turbines: Number:	2
Rating:	220 MWe
Steam conditions at turbine inlet:	
Temperature	255 (deg C)
Pressure:	44 (kg/cm^2)
Moisture content:	0.5 (%)
Flow:	1320 (t/h)
Type of condenser cooling	River
Reactor system containment	No containment

BG - 2 KOZLODUY - 2

Current status:	**OPERATIONAL**
I. GENERAL	
Station name	Kozloduy - 2
Region of Township	Kozloduy
Station Coordinates:	
Latitude (degrees, minutes):	
Longitude (degrees, minutes):	
Reactor Type:	PWR
Reactor System Supplier:	ATOMENERGOEXPORT
Turbine Generator Supplier:	ATOMENERGOEXPORT
Owner(s):	NATIONAL ELECTRIC COMPANY
Operator:	KOZLODUY NPP
II. MAILING ADDRESS:	
Station Address:	NPS Kozloduy 3320 Kozloduy Bulgaria
Station Telephone	(02)871312, (0973)71
Telex	33 416
Fax	(0973) 2591
Utility Address:	NEK 8 Triaditza str 1000 Sofia Bulgaria
Utility Telephone:	(02)86191
Telex	22707, 22708
Fax	(02) 875826

III. OUTPUT PER REACTOR UNIT:

	Design	Current
Nuclear thermal:	1375	1375
Gross electrical	440	440
Net electrical	408	408

IV. DATE OF:

State of Construction	April 1970
First critically	August 23, 1975
First synchronization to grid	September 27, 1975
Commercial Operation	November 5, 1975
Design Life Time	30 years

V. REACTOR CORE CHARACTERISTICS

Fuel material	UO_2
No of fuel rods per assembly:	126
Av. initial fuel enrichment	2.5 (w%)
Av. reload fuel enrichment:	3.6 (w%)
Cladding, material:	ZR
thickness:	0.65 (mm)
Fuel loading:	42 (tonne U)
Power density in fuel:	32 (kW/kg U)
Power density in core:	84.2 (kW/lit)
Linear power density:	12.5 (kW/m)
Discharge burnup, design av.	28600 (MWd/t)
Method of refuelling	off load
- design frequency of refuelling	12 (months)
- part of core withdrawn	33 (%)
Means of reactivity control:	H_3BO_3

VI. PLANT SYSTEMS

Reactor vessel, basic material:	LOW ALLOY STEEL
cladding material:	NO CLADDING
Primary system description:	
No. of primary pumps	6
Coolant: Material:	H_20
Mass flow through core:	39000 (t/h)
Outlet temperature:	298 (deg C)
Outlet pressure:	125 (kg/cm^2)
Steam generator(s): Number:	6
Type:	PGW-4E
Turbines: Number:	2
Rating:	220 MWe
Steam conditions at turbine inlet:	
Temperature	255 (deg C)
Pressure:	44 (kg/cm^2)
Moisture content:	0.5 (%)
Flow:	1320 (t/h)
Type of condenser cooling	River
Reactor system containment	No containment

BG - 3 KOZLODUY - 3

Current status:	OPERATIONAL
I. GENERAL	
Station name	Kozloduy - 3
Region of Township	Kozloduy
Station Coordinates:	
Latitude (degrees, minutes):	
Longitude (degrees, minutes):	
Reactor Type:	PWR
Reactor System Supplier:	ATOMENERGOEXPORT
Turbine Generator Supplier:	ATOMENERGOEXPORT
Owner(s):	NATIONAL ELECTRIC COMPANY
Operator:	KOZLODUY NPP
II. MAILING ADDRESS:	
Station Address:	NPS Kozloduy 3320 Kozloduy Bulgaria
Station Telephone	(02)871312, (0973)71
Telex	33 416
Fax	(0973) 2591
Utility Address:	National Electric Company 8 Triaditza str 1000 Sofia Bulgaria
Utility Telephone:	(02)86191
Telex	22707, 22708
Fax	(02) 875826

III. OUTPUT PER REACTOR UNIT:

	Design	Current
Nuclear thermal:	1375	1375
Gross electrical	440	440
Net electrical	408	408

IV. DATE OF:

State of Construction	October 1973
First critically	December 4, 1980
First synchronization to grid	December 17, 1980
Commercial Operation	January 28, 1981
Design Life Time	30 years

V. REACTOR CORE CHARACTERISTICS

Fuel material	UO_2
No of fuel assemblies:	349
No of fuel rods per assembly:	126
Av. initial fuel enrichment	2.5 (w%)
Av. reload fuel enrichment:	3.6 (w%)
Cladding, material:	ZR
thickness:	0.65 (mm)
Fuel loading:	42 (tonne U)
Power density in fuel:	32 (kW/kg U)
Power density in core:	84.2 (kW/lit)
Linear power density:	12.5 (kW/m)
Discharge burnup, design av.	28600 (MWd/t)
Method of refuelling	off load
- design frequency of refuelling	12 (months)
- part of core withdrawn	33 (%)
Means of reactivity control:	H_3BO_3

VI. PLANT SYSTEMS

Reactor vessel, basic material:	LOW ALLOY STEEL
cladding material:	NO CLADDING
Primary system description:	
No. of primary pumps	6
Coolant: Material:	H_20
Mass flow through core:	39000 (t/h)
Outlet temperature:	298 (deg C)
Outlet pressure:	125 (kg/cm^2)
Steam generator(s): Number:	6
Type:	PGW-4E
Turbines: Number:	2
Rating:	220 MWe
Steam conditions at turbine inlet:	
Temperature	255 (deg C)
Pressure:	44 (kg/cm^2)
Moisture content:	0.5 (%)
Flow:	1320 (t/h)
Type of condenser cooling	River
Reactor system containment	No containment

BG - 4 KOZLODUY - 4

Current status: OPERATIONAL

I. GENERAL

Station name	Kozloduy - 4
Region of Township	Kozloduy
Station Coordinates:	
Latitude (degrees, minutes):	
Longitude (degrees, minutes):	
Reactor Type:	PWR
Reactor System Supplier:	ATOMENERGOEXPORT
Turbine Generator Supplier:	ATOMENERGOEXPORT
Owner(s):	NATIONAL ELECTRIC COMPANY
Operator:	NPP

II. MAILING ADDRESS:

Station Address:	NPS Kozloduy 3320 Kozloduy Bulgaria
Station Telephone	(02)871312, (0973)71
Telex	33 416
Fax	(0973) 2591
Utility Address:	National Electric Company 8 Triaditza str 1000 Sofia Bulgaria
Utility Telephone:	(02)86191
Telex	22707, 22708
Fax	(02) 875826

III. OUTPUT PER REACTOR UNIT:

	Design	Current
Nuclear thermal:	1375	1375
Gross electrical	440	440
Net electrical	408	408

IV. DATE OF:

State of Construction	October 1973
First critically	April 25, 1982
First synchronization to grid	May 17, 1982
Commercial Operation	June 17, 1982
Design Life Time	30 years

V. REACTOR CORE CHARACTERISTICS

Fuel material	UO_2
No of fuel assemblies:	349
No of fuel rods per assembly:	126
Av. initial fuel enrichment	2.5 (w%)
Av. reload fuel enrichment:	3.6 (w%)
Cladding, material:	ZR
thickness:	0.65 (mm)
Fuel loading:	42 (tonne U)
Power density in fuel:	32 (kW/kg U)
Power density in core:	84.2 (kW/lt)
Linear power density:	12.5 (kW/m)
Discharge burnup, design av.	28600 (MWd/t)
Method of refuelling	off load
- design frequency of refuelling	12 (months)
- part of core withdrawn	33 (%)
Means of reactivity control:	H_3BO_3

VI. PLANT SYSTEMS

Reactor vessel, basic material:	LOW ALLOY STEEL
cladding material:	SS
Primary system description:	
No. of primary pumps	6
Coolant: Material:	H_20
Mass flow through core:	39000 (t/h)
Outlet temperature:	298 (deg C)
Outlet pressure:	125 (kg/cm^2)
Steam generator(s): Number:	6
Type:	PGW-4E
Turbines: Number:	2
Rating:	220 MWe
Steam conditions at turbine inlet:	
Temperature	255 (deg C)
Pressure:	44 (kg/cm^2)
Moisture content:	0.5 (%)
Flow:	1320 (t/h)
Type of condenser cooling	River
Reactor system containment	No containment

BG - 5 KOZLODUY - 5

Current status:	OPERATIONAL
I. GENERAL	
Station name	Kozloduy - 5
Region of Township	Kozloduy
Station Coordinates:	
Latitude (degrees, minutes):	
Longitude (degrees, minutes):	
Reactor Type:	PWR
Reactor System Supplier:	ATOMENERGOEXPORT
Turbine Generator Supplier:	ATOMENERGOEXPORT
Owner(s):	NATIONAL ELECTRIC COMPANY
Operator:	KOZLODUY NPP
II. MAILING ADDRESS:	
Station Address:	NPS Kozloduy 3320 Kozloduy Bulgaria
Station Telephone	(02)871312, (0973)71
Telex	33 416
Fax	(0973) 2591
Utility Address:	National Electric Company 8 Triaditza str 1000 Sofia Bulgaria
Utility Telephone:	(02)86191
Telex	22707, 22708
Fax	(02) 875826

III. OUTPUT PER REACTOR UNIT:

	Design	Current
Nuclear thermal:	3000	3000
Gross electrical	1000	1000
Net electrical	953	953

IV. DATE OF:

State of Construction	July 1980
First critically	November 5, 1987
First synchronization to grid	November 29, 1987
Commercial Operation	September 28, 1988
Design Life Time	30 years

V. REACTOR CORE CHARACTERISTICS

Fuel material	UO_2
No of fuel assemblies:	163
No of fuel rods per assembly:	312
Av. initial fuel enrichment	3.1 (w%)
Av. reload fuel enrichment:	4.4* (w%) 3.3 (w%)
Cladding, material:	ZR
thickness:	0.65 (mm)
Fuel loading:	75.2 (tonne U)
Power density in fuel:	45.5 (kW/kg U)
Power density in core:	111 (kW/lit)
Linear power density:	16.71 (kW/m)
Discharge burnup, design av.	40000* (MWd/t) 2700 (MWt)
Method of refuelling	off load
- design frequency of refuelling	12 (months)
- part of core withdrawn	50 (%)
Means of reactivity control:	H_3BO_3

VI. PLANT SYSTEMS

Reactor vessel, basic material:	LOW ALLOY STEEL
cladding material:	SS
Primary system description:	4 modules of steam gen.
No. of primary pumps	4
Coolant: Material:	H_20
Mass flow through core:	84800 (t/h)
Outlet temperature:	320.1 (deg C)
Outlet pressure:	160 (kg/cm^2)
Steam generator(s): Number:	4
Type:	PGW-1000 (horizontal)
Turbines: Number:	1
Rating:	1000 MWe
Steam conditions at turbine inlet:	
Temperature	274 (deg C)
Pressure:	59 (kg/cm^2)
Moisture content:	0.2 (%)
Flow:	5980 (t/h)
Type of condenser cooling	River
Reactor system containment	Reinforced, prestressed concrete

BG - 6 KOZLODUY - 6

Current status:	**CONSTRUCTION**
I. GENERAL	
Station name	Kozloduy - 6
Region of Township	Kozloduy
Station Coordinates:	
Latitude (degrees, minutes):	
Longitude (degrees, minutes):	
Reactor Type:	PWR
Reactor System Supplier:	ATOMENERGOEXPORT
Turbine Generator Supplier:	ATOMENERGOEXPORT
Owner(s):	NATIONAL ELECTRIC COMPANY
Operator:	KOZLODUY NPP
II. MAILING ADDRESS:	
Station Address:	NPS Kozloduy 3320 Kozloduy Bulgaria
Station Telephone	(02)871312, (0973)71
Telex	33 416
Fax	(0973) 2591
Utility Address:	National Electric Company 8 Triaditza str 1000 Sofia Bulgaria
Utility Telephone:	(02)86191
Telex	22707, 22708
Fax	(02) 875826

III. OUTPUT PER REACTOR UNIT:

	Design	Current
Nuclear thermal:	3000	3000
Gross electrical	1000	1000
Net electrical	953	953

IV. DATE OF:

State of Construction	July 1980
First critically	
First synchronization to grid	
Commercial Operation	
Design Life Time	30 years

V. REACTOR CORE CHARACTERISTICS

Fuel material	UO_2
No of fuel assemblies:	163
No of fuel rods per assembly:	312
Av. initial fuel enrichment	3.1 (w%)
Av. reload fuel enrichment:	4.4* (w%) 3.3 (w%)
Cladding, material:	ZR
thickness:	0.65 (mm)
Fuel loading:	75.2 (tonne U)
Power density in fuel:	45.5 (kW/kg U)
Power density in core:	111 (kW/lit)
Linear power density:	16.71 (kW/m)
Discharge burnup, design av.	40000* (MWd/t) 2700 (MWt)
Method of refuelling	off load
- design frequency of refuelling	12 (months)
- part of core withdrawn	50 (%)
Means of reactivity control:	H_3BO_3

VI. PLANT SYSTEMS

Reactor vessel, basic material:	LOW ALLOY CR-MO-NI STEEL
cladding material:	SS
Primary system description:	4 modules of steam gen.
No. of primary pumps	4
Coolant: Material:	H_20
Mass flow through core:	84800 (t/h)
Outlet temperature:	320.1 (deg C)
Outlet pressure:	160 (kg/cm^2)
Steam generator(s): Number:	4
Type:	PGW-1000 (horizontal)
Turbines: Number:	1
Rating:	1000 MWe
Steam conditions at turbine inlet:	
Temperature	274 (deg C)
Pressure:	59 (kg/cm^2)
Moisture content:	0.2 (%)
Flow:	5980 (t/h)
Type of condenser cooling	River
Reactor system containment	Reinforced, prestressed concrete

BULGARIA

THERMAL POWER PLANTS, DISTRICT HEATING PLANTS AND INDUSTRIAL COGENERATION PLANTS

1. This section of the report has the following main objectives:

- Review of the current status of existing thermal generating plants in Bulgaria including plants in the district heating and industrial sectors;

- Technical data collection for each unit - including location, and the year of commercial service, design basis, technical and major equipment data, current maximum and minimum capacities, availability, heat rates, scheduled maintenance and outage data, fuel type and composition, fuel availability, remaining life of existing equipment, annual electricity generation, annual and/or monthly fuel consumption, and production costs; and

- Review of operating and maintenance practices, equipment limitations, rehabilitation programs and schedules, identification of candidate plants for combined cycle operation, fuel switching scenarios, efficiency improvements, costs for rehabilitation and repowering, decommissioning or retirement schedules and review of projects under construction.

National Electric Company Power Plants:

2. Maritza East 1. This power plant is located in southeastern Bulgaria near Galabovo. Maritza East 1 has been in operation for 30 years. The plant has reached the end of its useful life. The plant has four 50 MW units supplying steam to a nearby briquette factory and two units of 150 MW, which have been decommissioned. The power plant, built during 1958 to 1963, has six 210 t/hr steam boilers supplying steam to the four 50 MW extraction steam turbines. The plant supplies nearly 480 t/hr of process steam at 180 °C and 4kgf/sq.cm to the briquette factory. In 1991, this plant generated about 990,000 MWh of electricity and 1.5 million giga calories of thermal energy. The reported plant overall gross heat rate was 2930 kcal/kWh. In 1991, the plant had 1229 employees. Under a U.S. TDP financed feasibility study, the study contractor, Bechtel, is considering several options to replace these units. Some of the options considered in the Bechtel study are: (1) a new 200 MW-250 MW plant to be built on the same site which would continue to supply steam to the briquette factory, (2) gradually closing down the briquette factory and installing one 400 MW condensing unit. The units in this power station are planned for decommissioning during 1995-1997. For this study, it was assumed that this plant will be replaced by a new lignite-fired 400 MW condensing power plant which will commence commercial operation by January, 1999. The estimated cost for this new plant in 1992 U.S. dollars is US$1300/kW. This estimate does not include interest during construction, contingency, etc.

3. Maritza East 2. This plant has four 150 MW units (units 1-4) which have been converted to direct firing of lignite, three 210 MW units (units 5-7) and a 210 MW unit (unit 8) under construction. The four 150 MW units were partially rehabilitated during 1984 -1986 and, during this rehabilitation the boilers were converted to direct firing of lignite. This, along with the reduction of main and reheat steam temperatures due to material problems, resulted in derating of these units to 130 MW each. The four units of 150 MW each were commissioned during the years 1966-1969. The original operating superheated and reheat temperatures for boilers and turbines were 570/570 °C and 565/565° C, respectively. In addition, the fuel was dried in fuel drying plants before being fed to the boilers. Because of material problems, the superheated and reheat steam temperatures were derated to

545/545 °C, resulting in reduced generating capacities for these units. The equipment in these units has nearly exhausted 50% of its useful life. These units are prime candidates for further life extension through rehabilitation. All the units are experiencing tube failures, due to high exit furnace flue gas temperatures caused by excessive slagging in the furnace. Much of the boiler's auxiliary equipment is experiencing problems, for example the coal mill is experiencing severe erosion due to high ash content in the lignite. The units are also subject to severe cycling, leading to further deterioration of equipment. Reduced capacities due to increased condenser back pressures were also reported. High percentage of unburnt carbon in the ash is also reported. Poor lignite quality, mainly because of excessive clay in the lignite, is causing material handling problems during certain weather conditions such as rain and snow.

4. For the study, first four units of 150 MW each are expected to undergo life extension through rehabilitation during 1994-1998. The three units of 210 MW each are relatively new and are operating well. Another unit of 210 MW capacity is to be completed with financing from EBRD and EIB. This unit along with unit 7 which share a common stack, will be provided with a flue gas desulfurization (FGD) unit. The estimated cost for life extension through rehabilitation for the old 150 MW units is about US$150/kW in 1992 U.S Dollars. This plant generated about 4.68 TWh during 1991 at an overall gross heat rate of 2784 Kcal/kWh. The plant currently employs 2,067 people.

5. Maritza 3-Dimitrovgrad. This plant has two units of 25 MW each, commissioned during 1951-1955, and they have reached the end of their useful lives. It also has one 120 MW unit, commissioned in 1971, which has severe boiler and turbine problems. This plant supplies steam to the district heating system. The 120 MW unit has been derated to about 75-80 MW. The deration is mainly due to bad fuel quality. Lignite fuel is supplied by Maritza West coal mine and contains excessive amounts of over burden. The plant is located in one of the most polluted areas of Bulgaria. Several options under consideration are: (1) Life extension through rehabilitation of 120 MW unit; (2) decommissioning of this unit and replacement of lost electric capacity by installing a new power plant in the Maritza East area and replace the existing district heating system by providing natural gas to individual consumers for heating; and (3) a combined cycle cogeneration system consistent with the steam demand for the district heating and industrial systems. In this study, an assumption is made to retire these units. Lost electricity capacity will be made up by a newly installed 400 MW plant in the Maritza East 1 complex. In 1991, Maritza 3 generated about 154 million MWh of electricity and 192,000 giga calories of thermal energy. This plant currently employs 363 people. Gross heat rate for the electricity production was 4029 kcal/kWh.

6. Maritza East 3. It has four units of 210 MW each, installed during 1978 through 1981. The units are operating well and standard rehabilitation and modernization of instruments and controls are anticipated in the near future. Retrofitting of these units with FGD is being considered. Lignite supplied is similar to that supplied to Maritza East 1 and 2. In 1991, this plant generated about 4.1 million TWh. This plant employed 1465 people in 1991.

7. Russe. This plant is located in Northern Bulgaria and on the banks of Danube. It has two units of 30 MW each, two units of 110 MW each and two units of 60 MW each. The 30 MW units were rehabilitated and are planned to be decommissioned in the year 2000. TOTEMA of Bulgaria is performing a feasibility study for life extension through rehabilitation of the 110 MW units. The current technical condition of these units is considered to be poor. The 60 MW units are operating well. The power plant uses anthracite coal imported from Ukraine. Availability of this coal has been a major problem for Bulgaria. Studies are being undertaken to convert the existing boilers to combust imported sub-bituminous coal. Some of the units can be converted to gas firing but this is not recommended. If continued use of gas is considered, combined cycle repowering may be technically and economically justifiable. The plant is experiencing problems with auxiliary equipment, such as circulating water pumps, water treatment plants, coal mills, etc. In 1991, this plant generated 521,744 MWh of electricity

and 786,388 giga calories of thermal energy. The gross heat rate for electricity production was 3094 kcal/kWh. The rehabilitation of these units are scheduled during the years 1995-2000. The two 30 MW units are expected to be retired during the period 1998-2000. In this study, an assumption is made to convert and to extend the life of the two 60 MW and the two 110 MW units to burn low sulfur imported coal. The estimated cost for conversion is about US$225/kW.

8. Varna. This plant is located on Varna lake some 20 km from Varna. It has 6 units of 210 MW each installed between 1968 and 1979. They are designed to use Ukrainian anthracite coal. As before (Russe), difficulty in supplying this coal is causing problems to the operation of this plant. Units 4 to 6 have been designed also to use natural gas. Units 1 to 3 are in poor technical condition, experiencing increased forced outages due to tube leaks in the steam and water circuits in the boiler. High cooling water temperatures resulting from inefficient cooling towers have caused reduced output. Currently Bechtel is performing a feasibility study for the life extension of these units including conversion of existing boilers to sub-bituminous coal. In 1991, this plant generated about 5.9 million TWh of electricity at a gross heat rate of nearly 2351 kcal/kWh. In this study, it was assumed that the first three units will be rehabilitated to burn low sulfur imported coal at a cost of US$225/kW. The other three units will undergo life extension through rehabilitation at a cost of US$225/kW and will continue to use the present imported Ukrainian coal.

9. Bobov Dol. This power plant is located around 100 km southeast of Sofia. It has three units of 200 MW, each commissioned between 1973 and 1975. Life extension and rehabilitation of these units are being studied by Bechtel. Bobov Dol mines are depleted and alternate sources of fuel supply are being evaluated. Boiler deterioration due to heavy slagging has been reported. In 1991, this plant generated about 1.6 TWh of electricity at a gross heat rate of about 3078 kcals/kWh. These units are scheduled for life extension through rehabilitation during the years 1994 to 1996. The boilers require modifications to accept blended coal or low sulfur imported coal. Low sulfur imported coal would be preferable as this would eliminate the need for expensive FGD units. The estimated cost for rehabilitation is US$173/kW.

District Heating Plants

10. Sofia. The Sofia plants are ideal for conversion to gas-fired combined cycle cogeneration and the thermal energy distribution system has huge losses and needs immediate modernization. Sofia has a population of about 1.1 million. Presently, the thermal energy is supplied by two thermal power plants (Sofia and Kostov plants), two local heating stations and several spare boiler plants. The Sofia plant was built in four stages. The first stage was built in 1949, and, except for occasional use of its boilers for producing process steam, most of the power generation equipment has been decommissioned. The second stage was built in 1958. This stage consists of three boilers rated at 170 tons/h of steam each and two extracting steam turbines rated at 25 MW each. This stage is in need of immediate rehabilitation through repowering or replacement. The third stage was completed in 1963 and is also a candidate for rehabilitation and/or repowering. This stage consists of two boilers rated at 220 tons/h each supplying steam to a 50 MW extraction turbine. The fourth stage was completed in 1985 and consists of a 220 tons/h boiler supplying steam to a back pressure turbine rated at 25 MW. Originally, the boilers were constructed to burn lignite and they have been converted to burn fuel oil and natural gas. In 1991, this plant generated nearly 485,000 MWh of electricity and 2.33 million giga calories of thermal energy. The gross heat rate for electricity generation was 1940 kcal/kWh. Natural gas is used as the primary fuel. A preliminary estimate for gas turbine repowering results in an increase in net electric generating capacity of about 280 MW based on current operations. The new net capacity for this plant after the retirement of units 4 and 5 is about 345 MW. (Units 4 and 5 are scheduled to be retired during 1994). Units 6 and 8 are recommended to be repowered, using gas turbines, during 1995 and 1996. The current estimate for repowered capacities were made consistent with the current design steam demands. The

estimated net capacities for units 6 and 8 are 104 and 240 MWs respectively. The estimated cost for repowering based on these capacities is about US$310/kW.

11. The Kostov plant was built in three stages. The first stage, completed in 1964, consists of two boilers, each rated at 220 tons/h, 9.6 MPa, 540 °C and two 30 MW turbine-generators. The second stage similar to the first stage was completed in 1968. The third stage was built in 1968 and is comprised of three boilers each rated at 220 tons/h, 13 MPa, 540 °C and one 66 MW turbine-generator. In addition, eight hot water boilers each rated at 100 kcal/h, were added between 1972 and 1982. The four 30 MW turbines need rehabilitation especially replacement of HP cylinders. This plant uses natural gas as the primary fuel. In 1991, this plant generated about 596,785 MWh of electricity and 2.7 million giga calories of thermal energy. The gross heat rate for electricity generation was 1706 kcal/kWh. Like the Sofia plant, this plant is an ideal candidate for rehabilitation and repowering with gas turbine combined cycle cogeneration. All the existing five units offer a potential for gas turbine combined cycle cogeneration. The estimated net capacity increase is about 735 MW. The estimated new net capacity for this plant is 870 MW. The cost for repowering, including rehabilitation of the existing steam cycle, is US$275/kW, based on new net capacity.

12. Pernik. Pernik is a major industrial town outside Sofia with a large district heating plant, Republika. This plant utilizes local low grade coal with high content of moisture, ash and sulfur. This plant supplies heat to a population of about 100,000 and process steam to several industries. Due to age, this plant is currently operating far below capacity. The current installed and available electric generating capacities are 155 MW and 75 MW respectively. This plant was built in three stages. The first stage was completed in 1952 and consists of two non-condensing turbines of 25 MW each and two steam generators rated at 34.7 kg/s at 7.8 MPa and 500 °C. This stage is expected to be decommissioned in the near future. The second stage was completed in 1958 and consists of three steam generators having the same parameters as the first stage and two 25 MW turbines (one of condensing type and the other double extraction type). The third stage was built in 1967 and consists of a steam generator rated at 61.1 kg/sec at 9.6 MPa and 540 °C and a condensing turbine rated at 55 MW. The second stage boilers and associated equipment are candidates for life extension through rehabilitation. This plant is ideal for the introduction of modern fluidized bed boiler technology. In 1991, this plant generated about 169,000 MWh of electricity and 583,000 giga calories of thermal energy. The gross heat rate for this generation of electricity was 3971 kcal/kWh. Units 3, 4 and 5 are scheduled to be rehabilitated during 1994 and 1995. Also a new 25 MW cogeneration unit (most of the equipment is on site) is scheduled to be installed in 1995 (assumed). The rehabilitation cost is estimated to be US$50/kW. This estimate does not include rehabilitation of the boilers, as electricity is considered as a byproduct from this plant.

13. Plovdiv. The Plovdiv plant has two 30 MW units and a 25 MW unit partially completed. Fuel is heavy fuel oil and permits have been obtained to convert to natural gas. Energoprojet is performing a life time assessment of existing equipment. The current plans are:

Completion of the 25 MW back pressure unit and conversion of the boilers from fuel oil to natural gas.

Modernization and rehabilitation of the existing equipment including HP cylinder replacement of turbine 2.

Decommissioning of turbine 1 and conversion of turbine 2 to combined cycle operation with two gas turbines 60 MW each (total gas turbine generation capacity 120 MW).

Introduction of a new 25 MW unit.

Because of the availability of natural gas, an early implementation of combined cycle operation would be beneficial and have the result of increased electricity production at high efficiencies.

14. In 1991, this plant generated about 122,000 MWh of electricity and 579,000 giga calories of thermal energy. The gross heat rate for the generation of electricity was 1751 kcal/kWh. Unit 1 is scheduled to be retired in the year 2005. Strong recommendations are made to repowered units 2 and 3 during the years 1996 and 1998, respectively. The new net repowered capacity is estimated to be about 260 MW. The estimated cost for this repowering is in the order of US$300/kW.

15. Avram Stoianov. It has one 30 MW unit and plans for installing an additional two 12 MW back pressure units are being considered. Fuel used is brown coal. In 1991, this plant generated about 1^6,500 MWh of electricity and 383,000 giga calories of thermal energy. The gross heat rate for electricity production was 2611 kcal/kWh.

16. Pleven & Shumen. Currently, Pleven plant has three 12 MW installed units with maximum generating capacity of 8 MW for each unit. Similarly, Shumen has three 6 MW units with maximum generating capacity of about 4 MW each. In both plants, large quantities of steam are provided to industries after expanding through back pressure turbines. These plants use natural gas and oil for fuel. In 1991, Pleven generated about 73,000 MWh of electricity and 878,000 giga calories of thermal energy. The gross heat rate for electricity generation was 1758 kcals/kWh. In 1991, Shumen generated about 54,000 MWh of electricity and 563,000 giga calories of thermal energy. The gross heat rate for electricity generation was 1260 kcals/kWh. Both plants offer a potential for repowering. The estimated new net capacities for Pleven and Shumen are about 295 MW and 160 MW, respectively. The estimated costs for these plants based on new net capacities are about US$475/kW and US$485/kW, respectively.

17. Russe West, Kazanlak, Gabrovo. In 1991, these plants generated 8100, 19,800, 18300 MWh of electricity, respectively and 207,000, 293,000, 312,000 giga calories of thermal energy, respectively. The gross heat rates for electricity generation were 1519, 1401, and 1450 kcals/kWh, respectively. Except for standard rehabilitation of these units, these plants are expected to continue operating through the year 2010 at the present ratings.

18. Pazardzik and Hoskovo Plants. There are no current plans to complete the construction of Pazardzik and Hoskovo plants.

19. Other Opportunities for Electricity Generation. There are several smaller district heating plants which generate electricity and several other gas fired district heating plants which currently produce only hot water. These gas fired hot water plants offer a potential for gas turbine conversion and are included in the table furnished by the COE.

Industrial Plants

20. The major industrial plants that produce electricity in a cogeneration mode are: a petroleum and petrochemical processing plant in Burgas, chemical plants in Devmia, a chemical plant in Svishtov, a metallurgical plant in Kremikovsi, a petrochemical plant in Pleven, a tires and fabric plant in Vidin, a chemical plant in Vratsa and a fertilizer plant in Stara Zagora. In 1991, all these plants combined with other smaller facilities generated about 3547 GWh. The reported total installed capacity for industry for the same year is 1040 MW. This results in an annual utilization of 3400 hours for the total installed capacity. This mediocre utilization is due to lack of availability of feed stocks required to operate these industrial plants. The plants at Burgas, Devina, Kremikovsi and Stara Zagora use or have the option to use natural gas as the primary fuel. Therefore these plants are candidates for gas turbine combined cycle repowering. Preliminary estimates for repowering capacity were made by matching gas

turbine/heat recovery steam generator output to the rated conditions of existing steam turbines. Gas turbine and waste heat boiler capacities were determined by prorating the performance of a standard industrial gas turbine. The major industrial plants that cogenerate electricity in substantial quantities are Burgas, Devnia, Svishtov, Kremikovsi, Vidin, Vratsa and Stara Zagora.

21. Burgas. Burgas plant is the largest petrochemical and petroleum processing plant in Bulgaria. Currently, the plant is operating at reduced capacity because of lack of feed stocks. As the Bulgarian monetary and policy situation stabilizes, this plant is expected to undergo modernization. This plant has a large need for process steam. For example, the reported average hourly steam needs during winter and summer are 1060 and 850 tons, respectively. This plant has two units of 60 MW and two units of 50 MW each operating on natural gas and/or fuel oil. These units are prime candidates for gas turbine epowering. The estimated net capacity after repowering is 1,082 MW. The estimated heat rates are in the range of 1500 to 1825 kcal/kWh.

22. Devnia. This is the largest chemical complex in Bulgaria. Major products include calcinated soda, soda products, sulphuric acid, phosphoric acid, chlorine, PVC, etc. The units in this complex are planned for modernization. The plant under normal conditions requires 1577 tons/h of steam for process purposes. But, after accounting for steam generated from available internal waste heat, a total of 1324 tons/h is needed from externally fired boilers. The plant has several cogeneration units, some operating on coal and others on natural gas and oil. Repowering opportunities exist for units operating on natural gas and the estimated repowered net heat rate is in the range of 1250-1390 kcal/kWh. The estimated cost for repowering is US$350/kW.

23. Kremikovsi. This is the largest metallurgical plant in Bulgaria. The plant is in need of modernization. The cogeneration plants use natural gas to produce steam and electricity. The estimated repowered capacity for this plant is 486 MW at a net heat rate in the range of 1230 to 1600 kcals/kWh. The estimated installation costs are US$310/kW.

24. Svishtov. This plant produces fibers. It has one 60 MW cogeneration unit. This unit uses coal for energy production.

25. NHK Pleven. This is a petrochemical plant and has a 60 MW cogeneration unit and uses heavy fuel oil for energy.

26. Vidin. This plant produces tires and fabrics and uses imported coal for energy production. The plant has a two 30MW cogeneration units.

27. Vratsa. This is a chemical plant which has two 30 MW cogeneration units. Natural gas and fuel oil are used as fuel for energy production. This plant has repowering opportunities and the estimated potential is 284 MW. The estimated cost for installation is 274 US$/kW.

28. Stara Zagora. This is fertilizer plant and has four 6 MW units and two 12 MW units. Currently, the steam for 6 MW units is generated by lignite-fired boilers and the 12 MW units by gas-fired boilers. Both the units offer a potential for repowering. The estimated repowered capacity is 720 MW.

29. All Others. There are several small cogeneration units with a total capacity of 55 MW.

Operation and Maintenance Practices

30. Energo Remont, a government owned company, is responsible for all major maintenance of the power and district heating plants. In general, once in five years these plants undergo a major reconstruction or rehabilitation, colloquially known as "Double General Remont". During this maintenance period, major parts in the boiler are replaced, the turbine is overhauled, other equipment replaced or reconstructed and tested for performance. The expected efficiency improvement from this major reconstruction is to achieve an efficiency only 4% less than design. Energo Remont has several factories which provides services needed for this reconstruction and also manufactures several major items of equipment used in these power plants. Another organization known as Tech Energy also assists in the design and production of small spare parts associated with electrical and controls equipment. Bulgaria can manufacture 60% of all its power plant spare parts requirements.

BULGARIA
HYDROPOWER PLANTS

Background

1. There are 1,975 MW of hydroelectric capacity in Bulgaria, making up approximately 18% of the COE/NEK's total installed capacity. Altogether, there are 87 operating hydroplants, however, the 11 largest plants have 77% of the capacity. The largest single hydropower project is the Belmeken-Sestrimo-Chaira hydropower complex (Rila complex) located in the Rila mountains. It currently has 735 MW of capacity split into three separate plants (Belmeken, Sestrimo, Momina Klisura) and accounts for 37% of Bulgaria's hydro capacity. The second big hydro power complex is the so called Vacha or Rhodope complex located in the Rhodope Mountains with four operating power plants (Dospat-Teshel, Devin, Antonivanovtsi, Krichim) and total capacity of 380 MW. The third large complex is the Arda river complex with three power plants (Studen Kladenets, Ivailovgrad and Kardzhali) with a total capacity of 274 MW. The available hydro capacity depends largely on the water supply in the reservoirs. In the winter of 1991-92, available hydroelectric capacity was between 750 and 900 MW, well below the total installed capacity, due to the drought in Bulgaria in 1990 and earlier which resulted in the partial depletion of the reservoirs. These capacity figures are based on normal operations on a monthly basis that would meet spring minimum reservoir levels needed for municipal and agricultural supply. In fact, instantaneous capacity can and did increase to approximately 1500 MW or above, though at a penalty to generation during other periods if minimum reservoir levels are to be met.

Hydro Power Stations in Operation (over 5 MW)

No	No. of Stat	River Basin	Hydro Power Station in Operation Over 5 MW	In Operation Since (year)	Installed Capacity (MW)	Design Annual Gener. (GWh)	Actual Av. Annual Generation (GWh)	Actual vs Design Generation
1	78	Rilska	Pastra	1924	5.50	29.00	29.80	102.76%
2	18	Iskar	Simeonovo	1927	6.28	49.00	35.41	72.27%
3	79	Rilska	Rila	1929	10.90	41.50	47.76	115.08%
4	56	Vacha	Vacha - 1	1933	14.00	21.60	21.88	101.30%
5	17	Iskar	Mala Tsarkva	1934	7.80	43.00	38.90	90.47%
6	39	Chaya	Asenitsa - 1	1951	7.20	30.00	24.94	83.13%
7	1	Lom	Kitka	1952	5.45	14.00	13.77	98.36%
8	32	Rositsa	Rositsa - 1	1954	7.50	22.00	21.94	99.73%
9	63	Tundja	G.Dimitrov	1955	7.00	17.00	13.00	76.47%
10	64	Tundja	Stara Zagora	1955	22.40	72.00	59.24	82.28%
11	6	Barzia	Barzia	1956	5.90	34.00	24.52	72.12%
12	19	Iskar	Pasarel	1956	32.50	77.00	68.52	88.99%
13	20	Iskar	Kokalyane	1956	22.40	73.00	73.78	101.07%
14	5	Barzia	Petrohan	1957	8.00	33.00	25.03	75.85%
15	16	Iskar	Beli Iskar	1957	16.80	42.00	29.81	70.98%
16	48	Stara	Batak	1957	40.00	167.70	126.62	75.50%
17	71	Arda	Studen	1958	62.40	217.00	189.76	87.45%
18	49	Stara	Kladena	1959	128.00	440.74	339.68	77.07%
19	50	Stara	Peshtera	1959	64.80	202.05	138.19	68.39%
20	57	Topolnitsa	Aleko	1962	8.00	29.00	21.56	74.34%
21	70	Arda	Topolnitsa	1964	106.40	165.00	114.34	69.30%
22	65	Tundja	Kardjaly	1965	14.40	32.60	16.38	50.25%
23	72	Arda	Jrebtchevo	1965	108.00	217.00	175.72	80.98%
24	80	S.Bistritsa	Ivailovgrad	1969	21.50	71.40	57.05	79.90%
25	81	S.Bistritsa	Popina Laka	1969	20.00	69.50	57.41	82.60%
26	82	S.Bistritsa	Lilyanovo	1971	14.20	48.10	38.66	80.37%
27	51	Vacha	Sandanski	1972	60.00	166.20	102.10	61.43%
28	55	Vacha	Teshel	1972	7.00	21.35	16.49	77.24%
29	54	Vacha	Vacha - 11	1973	80.00	197.40	164.93	83.55%
30	46	Sestrimska	Kritchim	1974	240.00	421.00	221.00	52.49%
31	47	Kriva	Sestrimo	1974	120.00	198.00	109.00	55.05%
32	53	Vacha	Momina Klisu	1975	160.00	245.00	167.90	68.53%
33	45	Kriva	Antonivanotsi	1976	375.00	556.00	306.00	55.04%
34	87	P.Bistritsa	Belmeken	1981	28.00	95.00	55.64	58.57%
35	52	Vacha	Spantchevo	1984	80.00	122.00	69.80	57.21%
36	86	P.Bistritsa	Devin	1992	21.20	70.80	0.00	0.00%
			Pirin					
			TOTAL		1938.53	4350.94	3016.51	69.33%

2. In 1991, which as was pointed out above was a dry year, hydroelectric plants in Bulgaria generated 2.44 TWh, 7.3% of total electricity generation by the COE and 6.3% of total electricity generated in the country. Based on the rated capacities of installed units, hydroelectric plants should generate 4.5 TWh in average precipitation years and 1.9 TWh in dry years. It appears that the economically exploitable hydropower potential in Bulgaria is approximately 10-12 TWh. However, this figure depends very much on the changing economics of hydropower and the value of the services it provides in addition to energy, some of which are instantaneous start-up, operational flexibility, load-following capability, peaking operability in a stop-start mode, and load management through pumped storage.

3. Considerable hydropower capacity is under construction or design in Bulgaria. Pumped storage capacity of 864 MW are under construction at Chaira which is part of the Belmeken-Sestrimo-Chaira complex. The first two units at Chaira, 2 x 216 MW, are almost complete and NEK has indicated that they will be completed by April 1993. The other two units, also 2 x 216 MW, are scheduled to be completed in 1995.

Belmeken-Sestrimo-Chaira Hydropower Scheme

4. This development occupies the north-eastern parts of Rila mountain and with its total potential of 2200 MW and potential annual electricity generation 3947 GWh is the biggest hydro power complex in Bulgaria. Breakdown of phases of development is follows:

- Phase I 735 MW/1190 GWh in operation since 1974
- Phase II 864 MW/1180 GWh under construction (pumped storage)
- Phase III -/270 GWh preparation
- Phase IV 600 MW/1203 GWh planned

5. The main reservoir of this project is Belmeken which will also serves as a head pond of Chaira pumped-storage power plant (second stage). Belmeken hydro power plant/pumped - storage power plant is the first stage of Phase I of the development with a total installed capacity of 375 MW and 560 GWh annual electric energy generation. Its turbines operate under a head of 730 m. In its powerhouse are installed five sets consisting of three parts - turbine, generator and pump. Pump capacity of each of the three component sets in the pumped-storage power plant is 52 MW. The second stage is Sestrimo hydro power plant with an installed capacity of 240 MW and generation of 430 GWh electric energy annually. The third stage is Momina Klisura power plant with a total installed capacity 120 MW. It has two 60 MW vertical Francis turbines and generates 200 GWh electric energy annually. The turbines are designed for a head of 251 m.

6. The operational results for the period 1976-89 lead to make the following conclusions:

- Water diverted and not used for power generation from 1976 to 1989 amounts to 1031 million m^3. In recent years these deviations run up to about 30% of the flow in the cascade. Thus, 140 million m^3 were diverted in 1987, 100 million m^3 of them for water supply to the capital Sofia. This has resulted in average annual loss of unproduced energy of the order of 218 GWh.

- In recent years there were some changes with respect to the role hydro power plants play in covering power system's load. This has found its expression in extending the duration of the day-time peak and backing up of failed capacities in the nation's power system.

- Sestrimo plant operates at maximum capacity 200 MW instead of the design capacity 240 MW. A reconstruction of the turbines and the generators will result in increasing power plant's capacity by about 40 MW and generation by about 64 GWh. In order to increase generation the reconstruction of part of the equipment is planned.

7. For the major pumped-storage (Phase II), the upper pond is Belmeken and the lower pond is Chaira dam (completed), with maximum geodetic difference in water level elevations being about 700 m. The underground machine hall is 22.5 m wide, 111.35 m long and 43 m high. Four single-stage pump-turbines, each 216 MW when generating and 195 MW when pumping, will be installed in it. Equipment for the power plant is being jointly manufactured by Toshiba Corporation (Japan) and Bulgaria engineering works. In the transformer cavern (12.60 m wide, 96.20 m long and 19.55 m high) will be installed six power transformers. Duration of Chaira pumped-storage power plant's continuous operation is limited by the storage in its lower reservoir, Chaira, with useful storage 4.37 million m^3 which guarantees maximum duration of operation of 8.5 hours when generating and 10.7 hours when pumping. With the commissioning of this power plant, the nation's electric power system will have another powerful hydropower plant with excellent load-following characteristics. The role and the operating functions of the Chaira pumped-storage power plant will be:

- operation during the peak demand hours;
- allowing the study operation of the nuclear and the thermal power plants for 24 hours during the year;
- overall system regulation of load;
- exchange power flows regulation; and
- short-term emergency reserve in the power system with excellent load-following characteristics.

8. Improving the operation of the existing parts of the hydropower development. The areas where significant efficiency improvements can be attained are as follows:

- Analysis of operation and the necessary reconstruction and modernization of the hydraulic structures: intake structures, canals, tunnels. Each step to decrease water losses by the proper operation of the intake structures will result in electricity generation increase.

- Modernization (upgrading) the main items of equipment in the hydropower plants in order to increase their effectiveness.

- Provision of alternative water sources for the main water consumers (except Sofia, this case is considered separately below).

These measures requires detailed technical and economic studies which shall take into account both the experience of operation of the existing capacities and the requirements for improvement.

9. Water supply Complex Rila. Currently, the deficit in water supplies to the capital is covered by withdrawing water from the Belmeken-Sestrimo power development. This worsens the power-generating capacity of the development with the reduction reaching 220 GWh per year. If this situation continues in the years to come, the approximately 100 million m^3 of water per year necessary for the capital will cause a reduction in generated electricity to the of 350 GWh per year from that cascade. Considering the additional electricity generated from these waters by the Iskar river power plants, the net losses from unsold electricity are estimated at 260 GWh per year, or about 13 million USD per year. With this in mind, the construction of the Rila water supply complex will result in restoring the design energy characteristics of the Belmeken-Sestrimo power development. The new Rila complex

envisages the transfer of 20 m^3/sec water from the Rilska river into the Iskar river. To that end two tunnels of dia 3.60 m each and 16 km and 9 km long would be driven. Total investments according to design are about US$22 million - US$18 million for the tunnels and US$4 million for the other structures. The construction program which covers pre-feasibility studies, geological investigations along tunnels routes, technical designs and tender documents, preparations for the tender and contracting and site construction will spread over a period of four years.

10. Transfer of water from Mesta river into Belmeken reservoir. An attractive solution which could improve considerably the operation of the Belmeken-Sestrimo development is the transfer in it of 75 million m^3 in an average dry year from the Mesta river. The Bulgarian Government favors such a scheme, but it would need to be agreed with the Greek Government. This scheme, together with the Rila water supply complex, would fill Belmeken reservoir at the beginning of the autumn-winter season. The additional transfer of waters into Belmeken-Sestrimo development will generate about 370 GWh annually on average and thus the 299 MW capacity in the existing power plants, currently experiencing water shortages, will be loaded to their full rating. Cherna Mesta dam would be built close to townships (Yakoruda) and part of the waters in the reservoir could solve the problems of their water supply. The scheme envisages the construction of 20 km of tunnels, 2 dams and 3 pump stations. The necessary capital investments amount to US$95 million and construction time is 4 years after agreement is reached with Greece.

Vacha Hydropower Scheme

11. The power plants of this scheme utilize the energy-producing potential of the river waters in the central and the western parts of the Rhodope mountain. After leaving the mountain these waters are utilized for irrigation and water supply. Until 1986, six power plants with total installed capacity of about 400 MW and annual electricity generation 774 GWh have been commissioned. The development incorporates the following projects:

A. Dospat - Devin section: in operation; it comprises:

- Dospat - Teshel hydropower development consisting of Dospat reservoir which stores 440 million m^3, pressure tunnel 46.2 km long and Teshel power plant - installed capacity 60 MW, annual generation 166 GWh, head 246 m, discharge 26 m^3/sec;

- Devin power plant: installed capacity 80 MW, annual electricity generation 122 GWh, head 156 m, discharge 73 m^3/sec;

- Osina supply conduit presently in design, to transfer 10.07 million m^3 of water from Osina river into Dospat reservoir thus increasing electricity generation of the existing power plants by 21.5 GWh; this figure will become 24.8 GWh after constructing the Sredna Vacha section.

B. Sredna Vacha section: under preparation; two variant schemes have been developed:

(i) Installation of pumped storage capacity; it comprises:

- Tsankov Kamak hydropower project comprising a reservoir storing 130 million m^3 and a pumped-storage power plant at the foot of the dam - installed capacity 420/352 MW (4 reversible pump - turbines 105/88 MW), annual electricity generation 842 GWh, annual consumption 985 GWh.

- Mihalkovo hydropower project comprising a 12 million m^3 water storage and a power plant at the foot of the dam with installed capacity 35 MW (2 turbines of 17.5 MW each) and annual electricity generation 56 GWh.

(ii) Construction of a hydropower project consisting of a dam impounding 130 million m^3 and a conduit - supplied hydropower plant with installed capacity 90 MW (2 turbines of 45 MW each) and annual generation 183 GWh.

C. Dolna Vacha section: in operation, it comprises:

- Antonivanovtsi hydropower project consisting of a 215 million m^3 water storage and a hydropower plant/pumped-storage power plant at the foot of the dam with total installed capacity 160/45 MW, annual electricity generation 245 GWh, annual electricity consumption 100 GWh.

- Krichim hydropower project consisting of a 15 million m^3 water storage, conduit-supplied hydropower plant Krichim with installed capacity 80 MW and annual electricity generation 195 MW, as well as two small hydropower plants (Vacha 2 and Vacha 1) with total installed capacity 21 MW and electricity generation 44 GWh.

Arda Hydropower Scheme

12. This development is situated in the southern most parts of Bulgaria, next to the border with Greece and Turkey. It consists of three big hydro projects, each one comprising a reservoir and a power plant at the toe of the dam. The river carries 2500 million m^3 in a year of average rainfall. The highest power plant is Kardzhali completed in 1964. The reservoir has a total capacity of 533 million m^3 and the installed capacity is 106 MW. Under an average head of 80.5 m, the design electricity generation should have been 165 GWh. In the last 15 years, it has been 119 GWh on the average. The first hydro project, Studen Kladenets, was completed in 1958. The dam impounds a total of 489 million m^3. The power plant has an installed capacity of 60 MW and should generate 217 GWh at an average head of 59.5 m. In recent years, generation has been 180 GWh on the average. In 1966, Ivailovgrad was completed immediately before the border with Turkey. This reservoir has a total volume of 180 million m^3. The power plant has an installed capacity of 180 MW and generates according to design a total of 217 GWh. Average head is 44 m. However, annual generation in the last 15 years has been 162 GWh on the average. The lower generation of Studen Kladenets and Ivailovgrad power plants is due to the smaller flow than the planned one, lower average head at the power plants because of intensive water releases from the reservoir and the worsened efficiency of the machines. In the case of Kardzhali reservoir, an additional problem is the need to maintain lower water levels for dam safety.

13. The planned development covers the stretch of Arda river from Srednogortsi village to the back side of Kardzhali reservoir. The construction scheme envisages four stages: Madan, Ardino, Liubino and Kitnitsa hydropower projects. Total installed capacity is 175 MW with annual electricity generation 485 GWh. A very important feature distinguishing Arda river from the other rivers in Bulgaria is the seasonal coincidence between the maximum river flow and the highest electricity consumption during the winter season thus allowing considerably smaller storages for annual retention of waters. The power plants will be operated only according to the needs of the nation's electric power system. Madan hydropower project is the upper - most stage of the cascade. It consist of Madan reservoir storing 135 million m^3, underground pressure tunnel 700 m long and Bial Izvor hydropower plant - installed capacity 46 MW, annual generation 110 GWh, head 88 m, discharge 62 m^3/ sec. Ardino hydropower project is the second stage. It consist of a power plant - installed capacity 51 MW, annual

generation 150 GWh, head 88 m, discharge 68 m^3/sec - and a 108 m high concrete arch dam impounding 93 million m^3 of water. Liubino hydropower project is the third stage. It consist of a 56 m high dam impounding 13 million m^3 and a hydropower plant - installed capacity 22 MW, annual generation 66 GWh head 38 m, discharge 68 m^3/sec. Kitnitsa hydropower project is the lower - most stage. It will consist of a 72 m high dam impounding 32 million m^3 and a power plant at the foot of the dam - installed capacity 38 MW, annual generation 106 GWh, head 55 m, discharge 80 m^3/sec. Beside the above power plants, another three run-of-river power plants will be built: Srednogortsi - installed capacity 66 MW, annual generation 22 GWh, discharge 30 m^3m/sec, head 26 m - taking water from three intake structures on Arda, Cherna and Madanska rivers. Malka Arda on the river of the same name - installed capacity 3.2 MW, annual generation 12 GWh, discharge 2.8 m^3/sec, head 13.7 m. Pesnopoi is at the back side of Kardzhali reservoir on Davidkovska Malka Arda river - installed capacity 6.8 MW, annual generation 21 GWh, discharge 7 m^3/sec, head 114 m.

Hydro Power Complexes on the Danube River

14. Danube river is the northern border of Bulgaria with Romania. This stretch of the river from Timok river to the town of Silistra is 471 km long. The geodetic head at the average multi-annual discharges is 21 m and the average slope of the river in the Bulgarian-Romanian section is 5 cm per km. The average annual flow is of the order of 173 billion m^3. This means a hydropower potential about 10,900 GWh, out of which 4,000 GWh can be utilized by Bulgaria.

The characteristics discharges of the Danube in that stretch are:

average multi-annual discharge	about 6,000 m^3/s
average maximum discharge	about 11,000 m^3/s
average minimum discharge	about 2,000 m^3/s
maximum discharge through that stretch	about 16,000 m^3/s

From the joint Bulgarian-Romanian design studies and investigations of the Danube river, there is a plan to build two hydro power projects - one at Nikopol-Turnu Magurele and one at Silistra Kalarash. These hydro power complexes would yield the following benefits:

- electricity generation;
- provision of water for the irrigation of lands in Northern Bulgaria;
- provision of water for the supply of industries and households;
- ensuring navigation throughout the whole year, thus allowing to increase load capacity of the vessels and eliminate losses from stoppage of navigation or partial loading of vessels; according to 1987 data losses amounted to US$500,000; and
- social effects from the improvement of infrastructure and communications.

The studies made envisage the following structures for each of the two projects:
- two hydro power plants (one for each country);
- two overflow concrete dams;
- two navigation locks;
- an earthful dam in the center of river bed and dikes connecting to the banks;
- railway and highway interconnecting Bulgaria and Romania;
- electric and telecommunication links between the two countries.

15. Along both banks of the reservoirs protection and drainage structures would be built and

Technical Characteristics of hydropower projects

Parameter		Nikopol-Turnu Magurele	Silistra-Kalarash
Retention level	m above sea level	30.75	18.65
Design head	m	9.9	7.6
Installed capacity in power plant of each country	MW	400	265
Electricity generation in power plant	GWh	2193	1640
Capacity investment in Bulgarian part	million USD	600	500

Benefits

Energy sector	54%
Agriculture	20%
Transportation	17%
Social benefits	6%
Industry	3%

Costs

Construction	70%
Erection	3%
Local machines	3%
Imported machines and equip	14%
Others	10%

There are also, of course, a number od drawbacks to these projects including high costs and flooding of land. A more thorough cost/benefit analysis needs to be carried out, but it is not at all clear that benefits out weigh the costs.

Iskar Hydropower Development Scheme

16. Iskar river is among the biggest rivers in Bulgaria. It comes from the Rila mountain and empties in the Danube. Its total length is 368.8 km, with a fall of 2,414 m. The water catchment area occupies a territory of 8,366 km^2 in western Bulgaria. The part of the river of interest to build small power plants is a stretch of the Iskar canyon crossing Stara Planina mountain between the towns of Novi Iskar and Cherven Briag. This stretch is 149 km long with a fall of 413 m or 41% of total fall. Average slope of river in this stretch is 2.77%. The water catchment area is about 7,000 km^2 covering the part of the Fore-Balkan, western Stara Planina and the Danubian rolling plain between the watersheds of the Ogosta river to the west and the Vit river to the east. In its upper course, the Iskar river flow is typically mountainous, and in the middle course, it is deformed under the influence of the Iskar multi-annual balancing reservoir on one hand, and the Sofia field and the low hills surrounding it on the other. The average flow in the considered stretch varies between 716 m^3 in the upstream section and 1,600 m^3 in the downstream section, the average discharge varying from 22.7 m^3/sec to 50.2 m^3/sec, respectively.

17. Existing Hydropower Plants. Thus far, three small hydro power plants have been built with a total installed capacity 2.3 MW and annual electricity generation 13 GWh, as follows:

- Mezdra plant near the town of Mezdra, head 8 m, total installed capacity 2.0 MW, annual electricity generation 10.4 GWh;
- Roza plant near Oslets railway station, head 3.6 m, total installed capacity 0.16 MW, annual electricity generation 1.7 GWh; and
- Iskra plant near Roman railway station, head 3.6 m total installed capacity 0.18 MW, annual electricity generation 1.0 GWh.

18. New Small Hydro Plants. In the prefeasibility study of 1982, 49 new sites for low-head hydro plants were explored. Total installed capacity will be 133 MW with annual electricity generation 712 GWh in a year of average hydrology. The annual hourly utilization is 5,700 hrs.

These small hydropower plants would be constructed in three stages:

Stage 1 - 1993-1994	five plants with total installed capacity 21 MW and annual electricity generation 120 GWh;
Stage 2 - 1994-1996	nine plants with total installed capacity 24 MW and annual electricity generation 134 GWh; and
Stage 3 - 1996-2000	35 plants with total installed capacity 88 MW and electricity generation 457 GWh.

Summarized data about the plant to be built at stage 1 are as follows:

- design discharge (per plant), 48-60 m^3/sec;
- total design head, 51 m;
- total installed capacity, 21 MW;
- total electricity generation, 120 GWh;
- hourly utilization, 5,600 hrs; and
- total investment US$21.5 million.

19. The feasibility study covers the stretch of Iskar river from Cherven Briag town to the river mouth at the Danube river. The considered stretch has a fall of 60 m and a length of 80 km, or 22% of total river length. Average slope of river in this stretch is 0.075%. In this stretch, only one hydro plant has been so far built, Koinare, utilized discharge 30 m^3/sec, head 6.4 m, installed capacity 2.1 MW, electricity generation 9.8 GWh in a year of average rainfall. The river's natural flow, in its lower course, varies between 1,649 million m^3 at Chomakovtsi site and 1.779 million m^3 at Bregare site. Power studies have revealed that the installed capacity of 22 MW can be utilized 1,459 hours annually in the peak periods. In the remaining 2,361 hours, electricity will be generated during the day-time hours - beyond both peaks. Total electricity generation will be 91.0 GWh in a year of average hydrology. The available potential in the lower course of Iskar river would be utilized by seven small hydro plants.

Small Hydro Plants in the Plain Stretch of the Maritza River

20. The Maritza river is the river with the biggest flow entirely in Bulgaria. Its average slope in the Pazardzhik-Svilengrad stretch is about .01% with a catchment area 16,720 km^2. The investigated stretch from Pazardzhik to Svilengrad lies in the Thracian lowland. Here the river crosses the Plovdiv and the Stara Zagora fields and the Haskovo rolling country. The section upstream of Pazardzhik is of no interest to hydro power development because of the small river flow. The construction of 20 small hydro plants is planned. The stages follow one after the other, and have low heads ranging between 4 and 9.6 m. The design discharge through all turbine sets has been assumed the same - 40 m^3/sec. A series of dikes will be built to protect the lowlands against flooding which is unavoidable when raising river level by 4 to 10 m. Average annual utilizability of installed capacities would be 2,700 h. The hydro plants will operate during the peak and the medium-load hours, depending on the multi-annual seasonal and daily regulation of the utilized river flow. Total installed capacity would be 220 MW. In a year of average hydrology, annual electricity generation would be 597 GWh.

Struma Hydropower Scheme

21. The Struma river starts at 2,180 m above sea level from the southern slopes of Vitosha mountain. Its water catchment area has an average height above sea level 900 m and is purely mountainous in character. The catchment area is surrounded to the north by Vitosha, Plana, Verila and Lozen mountains. The Struma river valley, in its middle course, is bounded by the western parts of the Rila - Rhodope massif between the eastern faulted slopes of the Osogovo-Belasitsa mountain range and the western faulted slopes of Rila, Pirin and Slavianka mountains. The explored stretch of the river covers three canyons--Zemen, Skrin and Kresna. Stage 1 covers Zemen canyon. A total of 10 low-head run-of-river power plants are envisaged for construction. Their total head is 79 m, river slope in this stretch being 100 m. Total installed capacity of plants is 12 MW, and total electricity generation 48 GWh in a year of average hydrology. The next stages of covers Skrin and Kresna canyons. In this case, the possibility of constructing another 17 low-head power plants with total installed capacity 47 MW and total annual electricity generation 190 GWh in a year of average hydrology has been considered. The annual utilizability of the plants is about 4,000 hours. Design discharge is between 10 and 60 m^3/sec. Total installed capacity of the power plants of Struma development would be 59 MW, and their annual electricity generation 238 GWh.

Preliminary Program for Rehabilitating and Upgrading Activities of Existing Hydropower Plants

22. Following the preliminary assessment of the operating hydropower plants under consideration, an estimation of the potentialities for upgrading of each power plant was given, including further studies to detail the respective measures which will result in capacity and generation increases in each power plant. The following studies would be required:

- Measure of sets efficiency, pressure and seepage losses in water conductor system, including the procurement of a complete set of measuring equipment.

- Post-measurement modifications to increase electricity generation:
  - repair of runners
  - replacement of runners
  - cleaning and insulation of penstocks
  - repair of supply conduits.

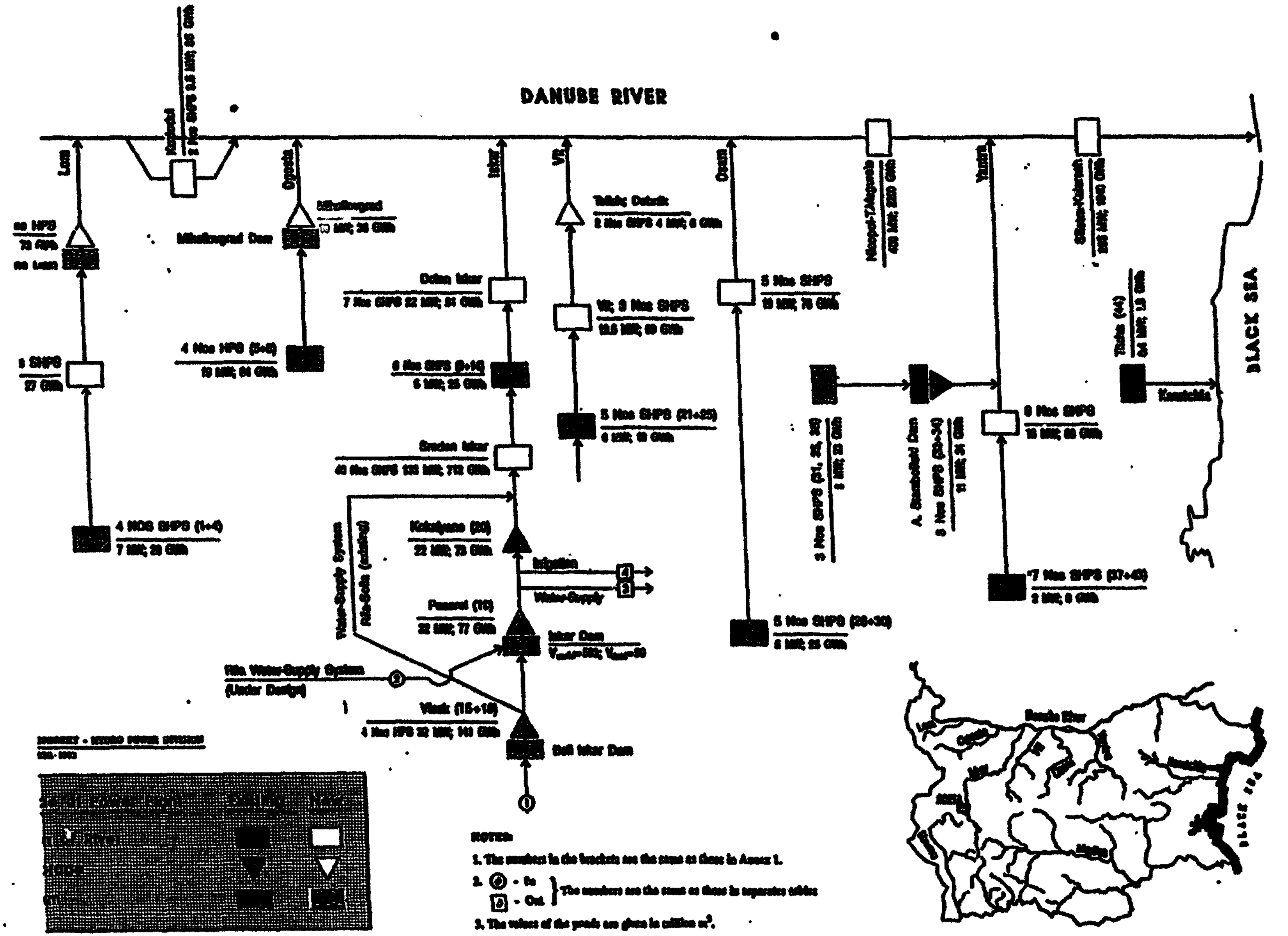
- Refurbishment and upgrading of:
  - pressure oil supply equipment of butterfly valve in valve chamber
  - axial bearings of hydro sets
  - repair sealing of spherical valves
  - sealing of butterfly valves and their control system
  - speed governors by using their own control system
  - butt sealing to turbine shaft
  - excitation system of hydro sets and voltage governors
  - system for power joint control

- Replacement of:
  - pumps, compressors and filters of cooling water and compressed-air systems
  - sealing of pump shaft to three-component turbine sets
  - sealing of joints of pressure penstock
  - gates to lower balancing pond
  - overspeed protection of pressure penstock
  - anti-corrosion protection of intake structures
  - generator circuit breakers
  - disconnecting switches
  - electrical equipment in outdoor switchgear
  - automatic synchronization system
  - equipment for secondary wiring
  - detectors and equipment for speed - following of sets
  - insulation of generator stator windings
  - voltage governors
  - level measurement system
  - system for automatic fire extinguishing of the field
  - instrumentation and automatic control equipment

  Installation of:
  - level indicators in upper and lower balancing ponds
  - ventilation system
  - system for power joint control
  - stationary fire extinguishing system in switchyard
  - fish protection structures

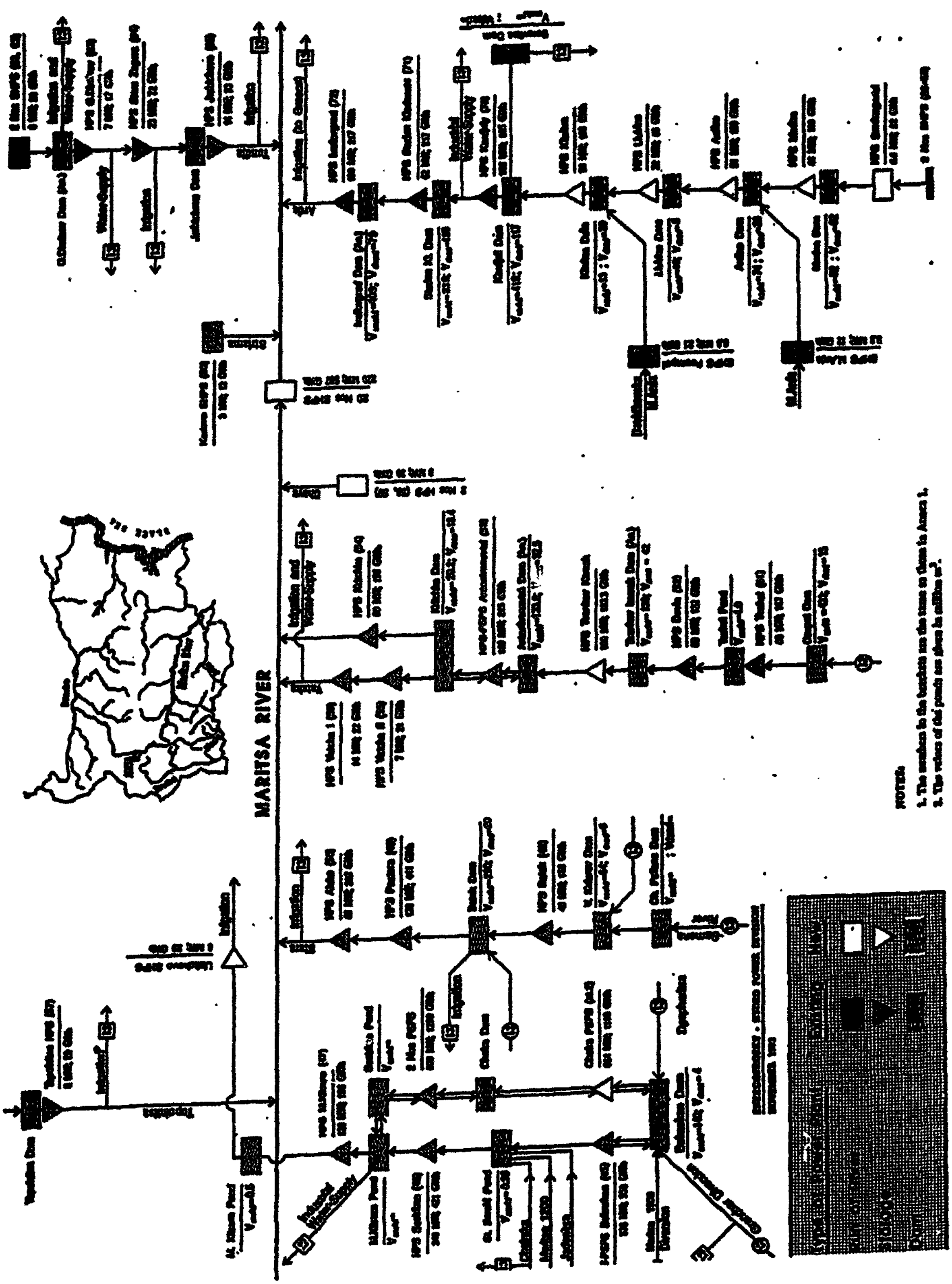
  Repair of:
  - gantries and platforms in switchyard
  - water conductor system (canals, tunnels and pipelines)
  - civil structures to remove leakages
  - power transformers
  - disconnecting switches of outdoor switchgear

  Construction of:
  - retaining walls on slope to switchyard, power plant and river banks
  - civil works to remove leakages

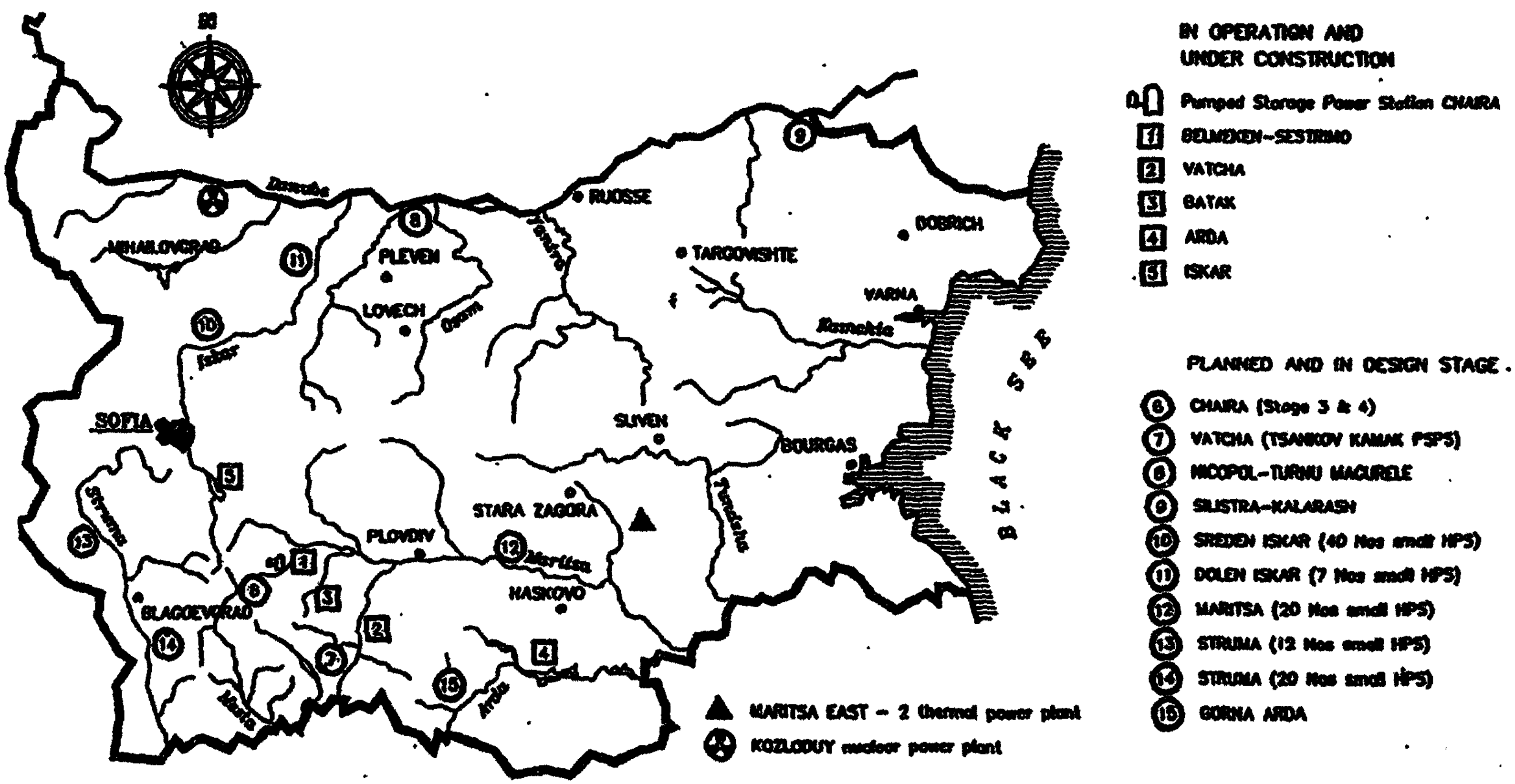


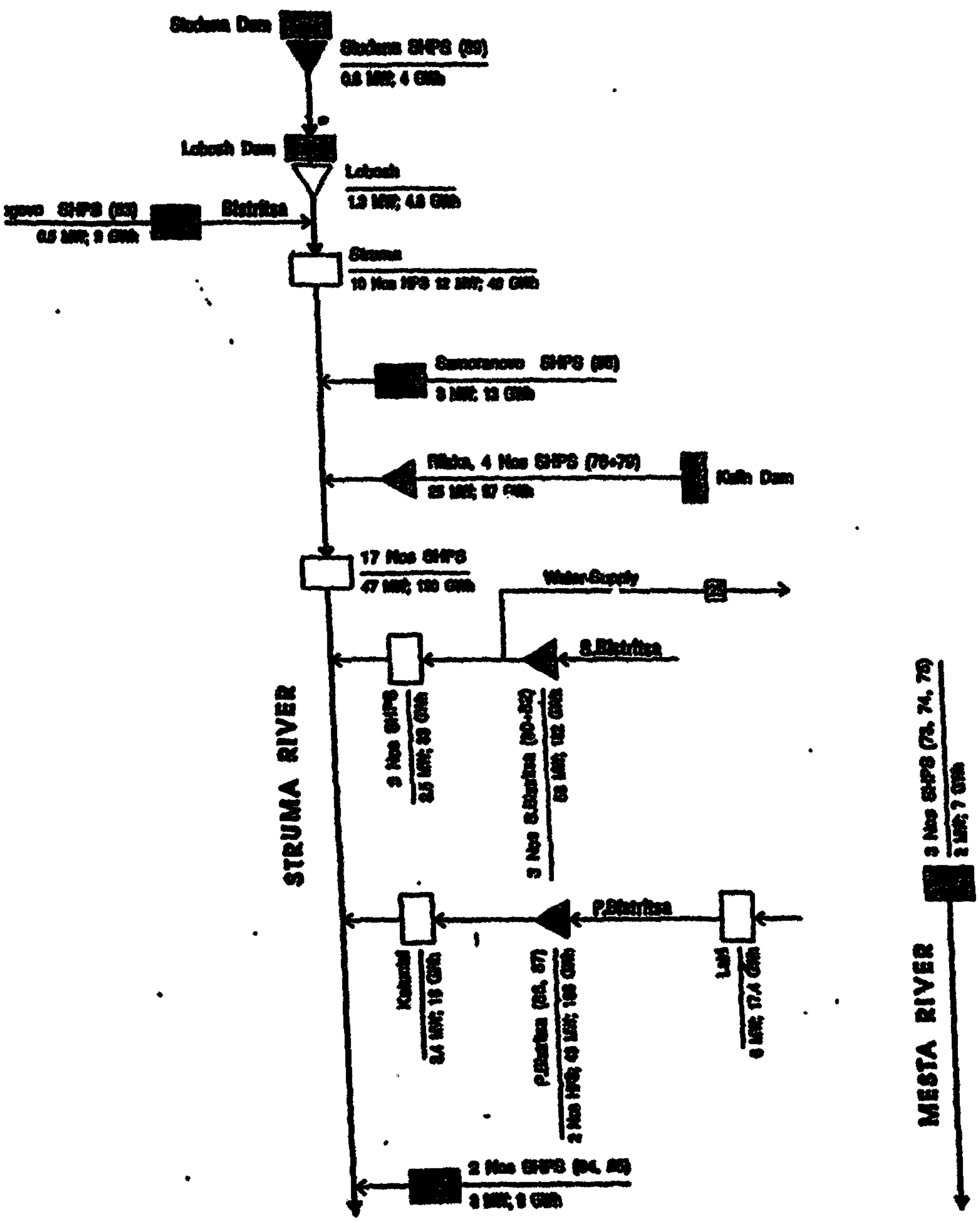
NOTES:

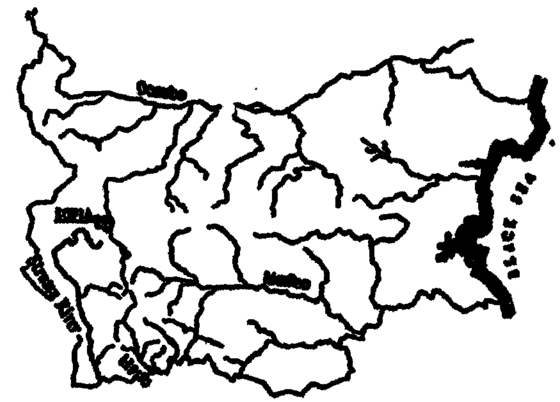
1. The numbers in the brackets are the same as those in Annex 1.
2. ⓪ - In, ◻ - Out } The numbers are the same as those in separate tables
3. The values of the ponds are given in million m³.


MARITSA RIVER

MAIN HYDRO POWER STATIONS IN BULGARIA







NOTES:

1. The numbers in the brackets are the same as those in Annex 1.
2. (6) - In, [6] - Out } The numbers are the same as those in separate tables
3. The values of the ponds are given in million m^3.

Type of Power Plant	Existing	New
Run of River		
Storage		
Dam		

BULGARIA

TRANSMISSION SYSTEM STATUS AND PERFORMANCE

The Current Transmission System

1. The high voltage system consist of 400 kV and 220 kV systems, but with one 750 kV interconnection (tie line). The subtransmission level is 100 kV and lower. In this report, attention is focused entirely on the 400 kV and the 220 kV system (the High Voltage system) which constitutes the bulk power transmission system.

2. The Internal High Voltage System. Both the 400 and the 220 kV systems form a closed loop configuration respectively, which essentially covers the entire country. The 220 kV system has several alternate paths that connect intermediate nodes of the main loop. The transmission system is not a bottleneck. Adequate transmission capacity is available to meet demand.

Basic Description and Statistics.

3. A brief description of the current Bulgarian System is given in this section. The 220 kV network was started in 1963/1964 and was essentially completed about 20 years ago. The 400 kV network is more recent and was started in 1973 and completed in 1984. Obviously, there has been on-going work, some expansion and upgrade, but the major portions of the systems were considered finished by the dates indicated. Transmission Lines. The total length of the 220 kV system is 2283 km, that of the 400 kV system is 1844 km and that of the 110 kV system is 7809 km (overhead) and 44 km (cable). The portion of the 750 kV lines within Bulgaria has a length of 85 km.

4. High Voltage Substations. The number of high voltage (HV) substations are:

- eighteen 220 kV
- eight 400 kV
- one 750 kV

The table below shows the list of the HV substations in Bulgaria.

High Voltage Substations in Bulgaria

Aleko	Kremikovtsi
Antonivanovtsi	Kula
Balkan	Madara
Belmeken	Maritza Iztok
Blagoevgrad	Maritza Iztok 2
Bobob Dol	Metalurgichna
Boychinovtski	Mizia
Braznik	Obraztsov Chiflik
Burgaz	Petrich
Varna	Pleven
Vetren	Plovdiv
GAES Chira	Pyrva Komsomolska
G. Oryakhovitsa	Radomir
Devin	Sestrimo

Dimo Dichev	Sofia Zapad
DMZ	Sofia Iug
Dobruya	Stolnik
Zlatitsa	Tvyrditsa
Kazichene	TES Sofia
Karnobat	Teshel
K. Georgiev	Uzundjovo
Kozludui	Chudomir

There are a total of 263 substations at the 110 kV level. All of the counts reflect the highest voltage at the substation.

5. Transformers. The number of 220 kV transformers is 37 and there are 25 400 kV transformers and two 750 kV transformers (each consisting of three single phase units). The total installed capacity of the transformers were made by TRO of the former East Germany and are rated at 630 MVA. They are of single phase design. There is a spare single phase unit available. The newer 400/100 kV transformers are of 3 phase design and were built by TRO. The transformers have proved to be quite reliable during the twenty years of service.

6. Transformers of two types have been purchased from a Ukrainian company. One is rated 200 MVA, 220/100 kV and the other 250 MVA 400/110 kV. Thirty 200 MVA and four 250 MVA transformers have been installed. In the spring of 1992, a Bulgarian transformer rated 133 MVA per phase was installed at Zlatitsa.

7. Shunt Reactors/Capacitors. There are several shunt reactors installed throughout the Bulgarian network. There are shunt reactors at:

NPP Kozloduy	-	3 units
Stolnik	-	3 units
Mizia	-	3 units
Dobrudja	-	3 units
TPP Dimo Dichev	-	1 unit
Sofia West	-	2 units
Blagoevgrad	-	2 units
Burgas	-	2 units

The reactors at Sofia West, Blagoevgrad and Burgas are connected to the tertiary winding at 31.5 kV. Each shunt reactor unit is 45 MVAR.

8. Static Var Compensators are installed at VARNA 750/400 kV substation. They are connected to the tertiary winding of the 750/40/15.75 auto transformers and operate in the range 100 MVAR (inductive) to 200 MVAR (capacitive) for each of two units.

9. Circuit Breakers. All breakers are air blast and are made by TRO of the former East Germany. All 220 kV breakers are rated at either 10,000 MVA or 15,000 MVA. There are no known problems with interrupting capability.

10. The 400 kV breakers were also built by TRO and have a rating of 25,000 MVA. The interrupting capability of these breakers is also considered adequate. There is an annual checking program for maintenance. The 400 kV breaker at Kozloduy has been replaced by an SF6 breaker built by ABB, but this has had some problems. The 750 kv breaker at VARNA is also SF6. There is a CB service center established at Plovdiv. The 400 kV substations use a breaker and a half scheme.

11. Interconnections (Tie Lines). The Bulgarian power system has interconnections with the neighboring countries of Romania, Yugoslavia, Greece, Turkey, and via Romania to Moldova and Ukraine (both of the former USSR). The tie lines are as follows:

(a) to Romania from Kozloduy - one double circuit 400 kV line and one 220 kV line;

(b) to Ukraine (via Romania) from Varna - one 750 kV line with 85 km to the Romanian boundary;

(c) to Moldova (via Romania) from Dobrujda - one 400 kV line with 207.7 km within Bulgaria. This line is series compensated;

(d) to Greece from Blagoevgrad - one 400 kV line with 72.4 km within Bulgaria;

(e) to Turkey from Thermal Power Plant Dimo Dichev - one 400 kV line with 59.1 km within Bulgaria;

(f) to Yugoslavia from Sofia West - one 400 kV line with 37 km within Bulgaria;

(g) to Yugoslavia - there are also three 100 kV lines, as follows:

- from Breznick 64.1 km
- from Petrich 49.32 km
- from Kula 40.3 km

12. The Bulgarian power system is part of the Integrated Power System (IPS) consisting of:

- Bulgaria
- Hungary
- former East Germany
- Poland
- Romania
- the Southern USSR Network (Ukraine and Moldavia)
- Czechoslovakia

13. System Needs. Because of the age of the equipment, operating and maintenance costs are increasing. The Bulgarian authorities would like to use the newer generation of circuit breakers, but because of high cost, the replacement will be done incrementally. Serious problems are anticipated with the ten operating (total of 13) 210 MVA single phase transformers which have been in operation since 1973. They have not been sent for factory rehabilitation. Only the necessary electrical and small repair has been done on site. These should be replaced within 3-4 years. The work has already been started at Mizia, for which a contract has been executed. Talks have been conducted to arrange factory facilities in Bulgaria. The fifteen 45 MVAR shunt reactors have maintenance problems. They were not adequately tested in the factory. Their circuit breakers need to be replaced. It is estimated that U.S. $10 million is needed to replace the six shunt reactors that have failed. For some of the 400 kV lines, the conductor

and ground wire need to be replaced because of loss of mechanical strength. Due to the reduction in industrial demand, the system is experiencing high voltages during off-peak load conditions. Studies have indicated that 200 MVAR reactors are needed at two locations, tentatively, Varna and Sofia West. Currently, some unconventional means are being taken to keep the voltages within acceptable limits. In some cases, this has meant switching out some 400 kV lines and the 750 kV lines and has resulted in higher losses. All investigations have shown that the short circuit levels in the 400 kV, 220 kV and the 110 kV systems are below the capabilities of the circuit breakers even with the addition of the new units at Belene (now cancelled) and with a hypothetical third nuclear plant at Silestra or Burgas. Therefore, given that short circuit studies will need far more extensive 100 kV data collection by the World Bank team, it does not appear that such studies should be conducted when studying the various scenarios. If necessary, NEK could be asked to perform these studies since the input is already available to them. All 400 and 220 kV transformers were made by the ex-German Democratic Republic and are out of production. There is a lack of spare parts, so reserve sets are used to replace damage. These should be replaced starting in a few years. There appears also to be a problem with disconnects which are operated by pressurized air. The reliability is not high.

Planned Expansion of the Transmission System

14. Recent studies conducted by the Bulgarian experts have indicated that the 400 kV system will be adequate for the foreseeable future and a higher bulk power transmission voltage will not be necessary. Furthermore, it is planned not to expand the 220 kV system - future expansions will be limited to the 400 kV and the 110 kV transmissions. A 400 kV line from Stolnik to Zlatitsa has been completed since 1989. A 400 kV line from Zlatitsa to Korlovo is 60-70% complete. A double circuit 400 kV line between Korlovo and Plovdiv was planned, but construction has been deferred. Similarly, the double circuit 400 kV line between Korlovo and Tsaravetz is deferred. A new 400 kV substation at Tsaravetz connected to the Mizia-Varna 400 kV line was also planned. This would enable the demand in that region to be supplied from the 400 kV network instead of the 220 kV network; thereby reducing transmission losses. Another 400 kV substation at Dobrich, where a synchronous condenser would be installed was planned. The synchronous condenser has been acquired, but is presently not connected to the network, since work at Dobrich has been stopped. There were also plans to add 400 kV transmission to the NPP Belane, but the cancellation of the latter has also resulted in the cancellation of the transmission lines. A 220 kV line from Kozloduy NPS to Vidin is under construction. This is configured for a double circuit line and work on this has also been temporarily stopped. It is about 50% complete.

Interconnections and Trade

16. As noted previously, the Bulgarian power system is interconnected with all the neighboring countries which are Romania, Turkey, Greece, Yugoslavia and also to Moldavia and Ukraine of the former Soviet Union. In the past, about 800 MW could be imported from the Soviet Union (Ukraine) at periods of peak demand with 4-5 TWh imported annually. This was imported over the 750 kV line and was under a contractual agreement. In 1992, the expected energy import was about 2 TWh. Though because of problems at Kozloduy actual imports were about 3.3 TWh. The contractual agreements are expected to be renewed annually. Historically, a substantial part of the peaking capacity and spinning reserve has been provided by the Interconnected Power System (IPS) of the CMEA countries. One justification cited for the use of a 750 kV line to the former USSR was that it would have sufficient capacity to provide the additional generation needed within Bulgaria in the even of the loss of one 1000 MW unit at NPP Kozloduy. Frequency regulation was the responsibility of the IPS and flow occurred on the 400 kV and 750 kV lines for this purpose. Bulgaria's trade in electricity with Romania, Greece, Turkey and Yugoslavia is small. Trade with Romania is limited because of capacity shortages in Romania; with Greece and Yugoslavia, trade is limited because, while Bulgaria is part of the IPS, Greece and Yugoslavia belong to the UCPTE, and IPS and UCPTE do not operate in parallel. Turkey is apparently a high cost energy producer and so trade with it is limited. Thus, the only major trade agreement is with Ukraine, but there is serious concern about the ability and willingness of Ukraine to provide the energy and capacity in future years, including 1993.

17. Possible synchronous operation within the UCPTE (hence disconnecting Bulgaria from the IPS) will require the Bulgarian power system to meet UCPTE requirements for controllability, frequency and tie line regulation, N-1 security, reactive power support, voltage stability, etc. While the load-frequency control system is one item in the World Bank loan, and the tripartite studies with Yugoslavia and Greece provide some encouragement about possible operation within UCPTE, further studies and upgrades are likely to be needed before this can be a reality. At present, the optimum strategy for Bulgaria's electric power sector regarding interconnection and trade would appear to be:

1. Continue agreement with Ukraine.

2. Gradually upgrade the electric network and dispatch and control capabilities to meet UCPTE standards.

While electrical generation is not the subject here, clearly any increases in internal energy production and improvements in utilization will help to reduce the dependence on imports.

Figure 2

26. Схема на електрическите мрежи 220, 400 и 750 kV

26. Схема электрических сетей 220, 400 и 750 kV.

26. Scheme of the 220, 400 and 750 kV electric networks.

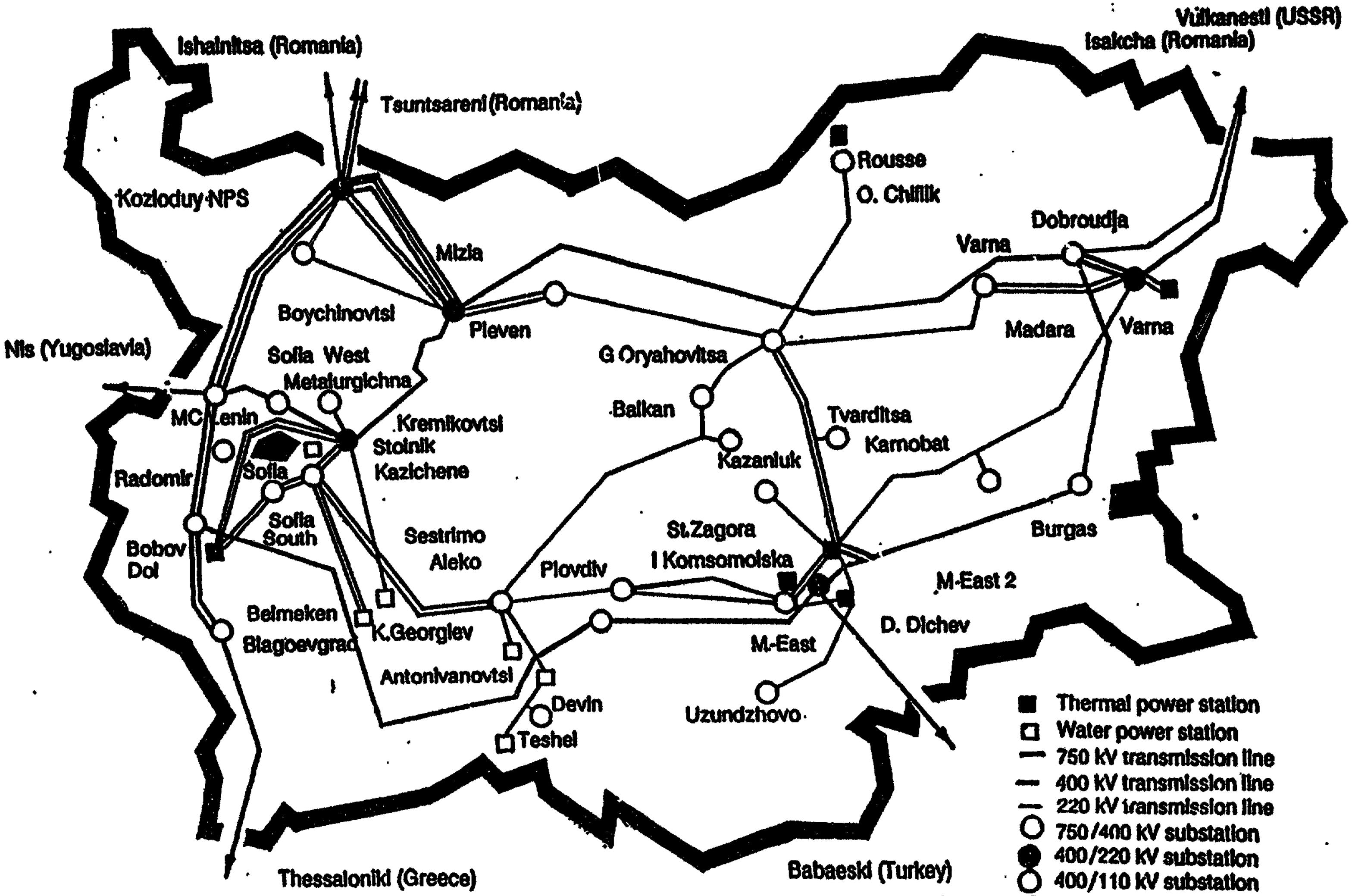
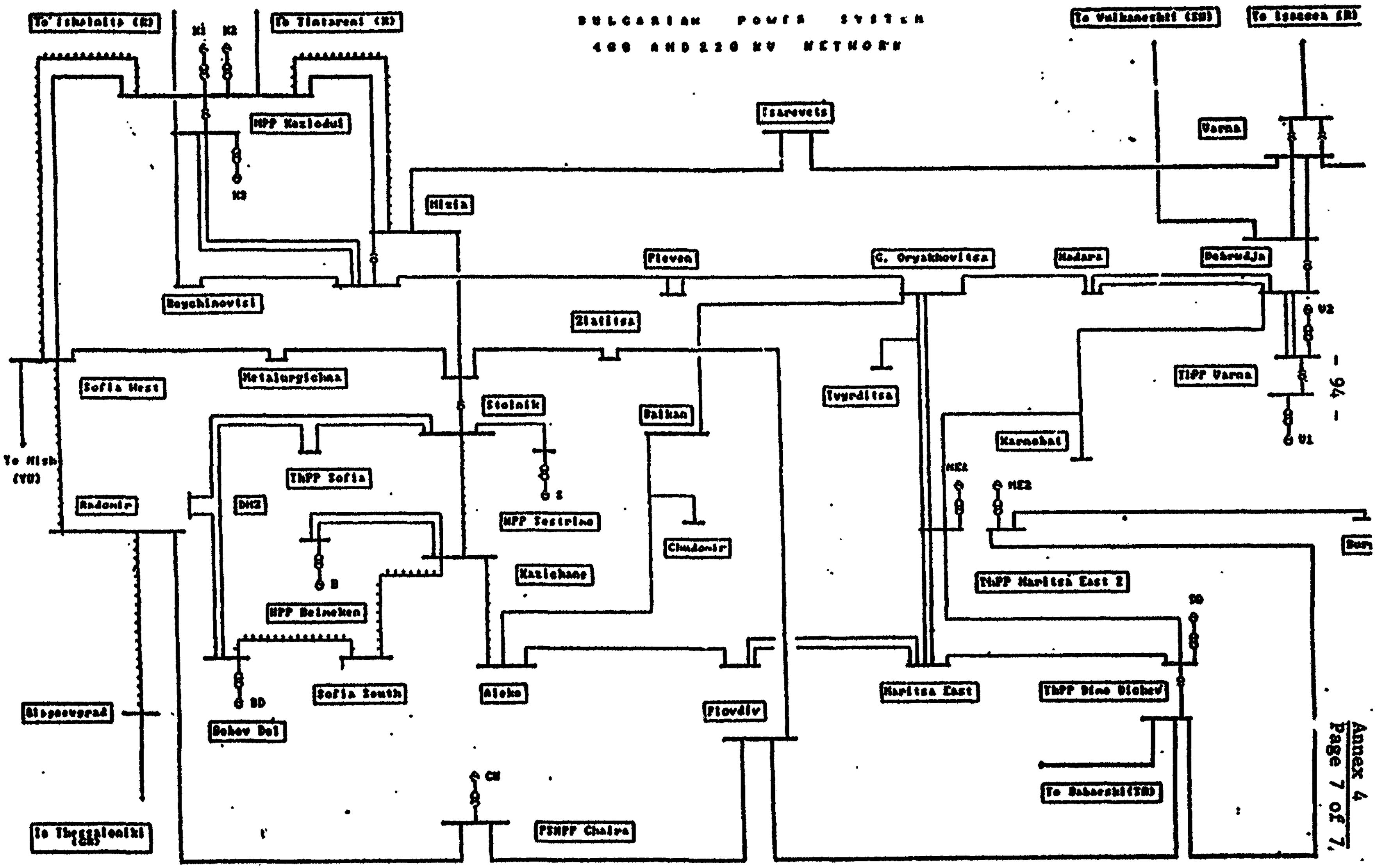


Figure 3

BULGARIAN POWER SYSTEM
400 AND 220 KV NETWORK



BULGARIA

SYSTEM PLANNING RESULTS

Least-Cost Generation Expansion Programs for the 18 Options Considered

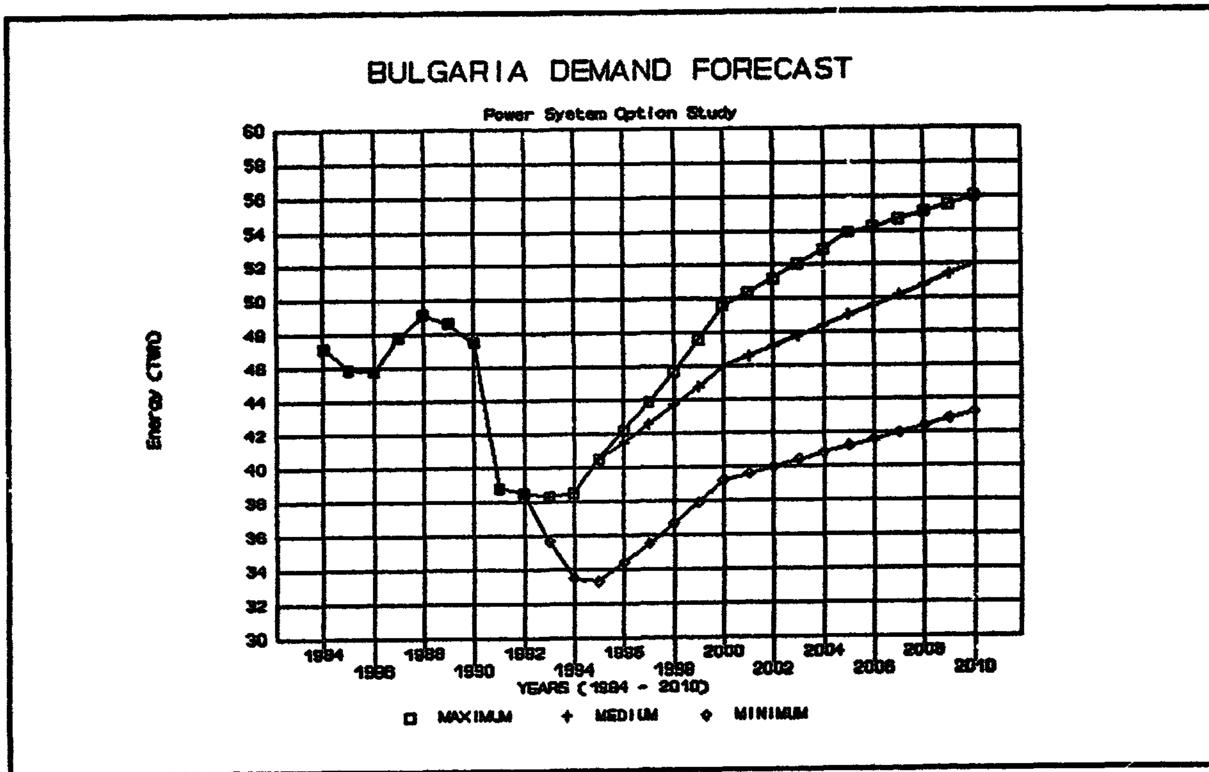


Figure 5.1

1. The 1992 G-7 Munich meeting communique has suggested measures related to the safety of the nuclear power plants in the countries of the former Soviet Union and Central and Eastern Europe including a preparation of studies by the World Bank in cooperation with the IEA. The objective of the studies is to assess power sector strategies and financing requirements in order to ensure the reliable supply of electricity if and when nuclear facilities are scheduled for modifications or shutdown for safety reasons. <u>The studies do not provide safety recommendations for the nuclear facilities, but rather analyze alternative electricity supply for various nuclear electricity supply scenarios.</u>

2. The study has been prepared by the World Bank in cooperation with IEA and the Government of Bulgaria in response to the Group-7 suggestion. The preparatory work was initiated by the World Bank and IEA mission which visited Bulgaria in November 1992 in order to: (a) obtain from the Bulgarian authorities possible scenarios for the rehabilitation or closure of the nuclear units at Kozloduy; (b) discuss and agree on the electricity demand forecasts; (c) discuss fuel supply options; (d) review the status of the power sector supply capacity; (e) discuss the interconnection, exchange and trade options; (f) discuss the basic assumptions and constraints for system development; and (g) prepare and verify power system data base as a first step in the preparation of the study. The intensive work and cooperation of the Bulgarian experts resulted in the successful mission. However, in some of the cases, data are still lacking due to: (a) unavailability of the information; (b) different methodology of preparation

or format of data; and (c) additional resources required for the data preparation. As a result, some of the analysis are based on publicly available information and the best professional judgements.

3. The main characteristic of the Bulgaria energy sector is a shortage of domestic primary energy resources. The country has in abundance low quality lignite, and relatively little hydro potential compared with its neighbors. This poverty of resources has led to an extraordinary dependance on the Soviet Union for supplies of every resource and for the technology to utilize them. Most of oil, all gas, some electricity and even significant quantities of coal were all imported from the Soviet Union. As a result, the energy policy was to concentrate development in the nuclear and coal sectors.

TABLE 5.1: DEMAND FORECASTS

YEAR	MINIMUM			MEDIUM			MAXIMUM		
	PEAK LOAD (MW)	ANNUAL ENERGY (TWh)	LOAD FACTOR %	PEAK LOAD (MW)	ANNUAL ENERGY (TWh)	LOAD FACTOR %	PEAK LOAD (MW)	ANNUAL ENERGY (TWh)	LOAD FACTOR %
1993	6370	35.7	64.0	6840	38.5	63.9	6840	38.5	63.9
1994	6050	33.5	63.2	6870	38.5	64.0	6870	38.5	64.0
1995	5950	33.3	63.9	7230	40.5	63.9	7230	40.5	63.9
1996	6140	34.4	64.0	7410	41.5	63.9	7540	42.2	63.9
1997	6340	35.5	63.9	7610	42.6	63.9	7840	43.9	63.9
1998	6550	36.7	64.0	7800	43.7	64.0	8160	45.7	63.9
1999	6770	37.9	63.9	8000	44.8	63.9	8500	47.6	63.9
2000	6880	39.2	65.0	8070	46	65.1	8700	49.6	65.1
2001	6950	39.6	65.0	8180	46.6	65.0	8840	50.4	65.1
2002	7020	40	65.0	8280	47.2	65.1	8980	51.2	65.1
2003	7090	40.4	65.0	8390	47.8	65.0	9140	52.1	65.1
2004	7160	40.8	65.0	8490	48.4	65.1	9280	52.9	65.1
2005	7230	41.2	65.1	8600	49	65.0	9440	53.8	65.1
2006	7300	41.6	65.1	8700	49.6	65.1	9510	54.2	65.1
2007	7370	42	65.1	8810	50.2	65.0	9600	54.7	65.0
2008	7440	47.4	65.1	8910	50.8	65.1	9670	55.1	65.0
2009	7510	42.8	65.1	9020	51.4	65.1	9740	55.5	65.0
2010	7580	43.2	65.1	9120	52	65.1	9820	56	65.1

Table 5.2: Monthly Load Duration Curves

Hrs	Jan. (MW)	Feb. (MW)	March (MW)	April (MW)	May (MW)	June (MW)	July (MW)	August (MW)	Sept. (MW)	Oct. (MW)	Nov. (MW)	Dec (mw)
0	6781	6712	6252	5530	4912	4850	4878	4905	5077	5908	6678	6820
32	6521	6475	5805	5128	4384	4546	4631	4705	4640	5344	6265	6441
64	6424	6364	5677	4934	4252	4480	4566	4629	4514	5137	6113	6286
95	6311	6255	5596	4845	4166	4413	4486	4577	4455	4982	6007	6147
127	6190	6162	5519	4753	4088	4341	4431	4521	4402	4845	5899	6035
159	6078	6066	5437	4663	4022	4281	4386	4460	4333	4744	5809	5970
191	5994	5980	5349	4583	3955	4229	4351	4413	4262	4629	5714	5886
222	5905	5901	5269	4501	3897	4180	4307	4365	4203	4530	5618	5769
254	5820	5825	5199	4420	3843	4141	4258	4321	4150	4454	5524	5697
286	5744	5751	5112	4316	3785	4105	4228	4277	4108	4365	5447	5608
318	5644	5670	5010	4219	3733	4068	4183	4235	4064	4274	5371	5492
349	5507	5584	4922	4139	3690	4025	4149	4195	4012	4188	5294	5374
381	5353	5490	4843	4056	3645	3979	4073	4137	3950	4105	5180	5258
413	5215	5356	4745	3975	3592	3912	3967	4018	3863	4014	5051	5137
445	5084	5178	4645	3898	3537	3832	3862	3982	3756	3936	4880	4999
476	4966	4996	4564	3826	3479	3758	3771	3801	3654	3856	4743	4824
508	4836	4848	4477	3751	3415	3680	3699	3721	3558	3771	4604	4638
540	4733	4708	4388	3684	3348	3613	3609	3617	3447	3690	4471	4475
572	4638	4575	4324	3623	3268	3458	3521	3524	3376	3592	4339	4321
603	4519	4430	4252	3539	3177	3462	3463	3464	3328	3504	4216	4179
635	4402	4289	4150	3446	3092	3402	3416	3420	3245	3399	4108	4038
667	4268	4130	4004	3352	3012	3334	3353	3371	3151	3315	3989	3905
699	3977	3979	3820	3274	2917	3202	3219	3192	3030	3209	3829	3783
730	3622	3569	3472	3041	2696	2926	3069	2929	2670	2857	3308	3535

4. The second important characteristics is high energy consumption due to a high proportion of power-intensive industry. Of total power use, 43% went to industry in 1989 - half of it consumed just by the chemical and machine building industries. The domestic sector consumes about 20% of all electricity, while commercial sector takes 10%. Otherwise, a big chunk of the power production is apparently written off as losses or consumed by the energy industries, particularly coal.

5. The safety concerns relative to the Kozloduy nuclear power plant as well as uncertainties in supply and higher cost of the imported fuel in combination with deteriorated characteristics of the generation capacity brought Bulgaria electricity supply below demand during the winter season. The supply situation would be critical if Bulgaria did not experience in the same period sharp decline in the electricity demand. Electricity imports was complicated by lack of financial resources and unreliable supply from the Integrated Power System (IPS). Studies done by the Greek, Yugoslav and Bulgarian authorities have shown that parallel operation with Greece and Yugoslavia (hence UCPTE) does not indicate any serious technical problem. However, this option is also very limited due to blockade imposed on Yugoslavia by the UN and the difficult economic situation in Bulgaria.

6. Demand Forecast. Three demand forecasts have been prepared in conjunction with NEK. These are a minimum, a medium and a maximum forecast presented in Table 5.1 and Figure 5.1. These forecasts assume a comparatively constant system load factor over the forecast period of around 65%. This is comparable with the present load factor of 64%. The forecasts includes auxiliary consumption within the stations. Generation planning also requires a good representation of the system loading pattern and information has been collected from NEK of hourly loadings over the past 20 years. These values have been averaged on a normalized basis and monthly load duration curves derived. Table 5.2 gives details of load duration curves. System demand is higher in the winter than in the summer due to heating loads, and the annual peak occurs in December. Detailed changes in these will undoubtedly occur as the consumer mix changes with the evolving economic situation.

7. Existing Power System. The breakdown of the existing generation capacity of the Bulgarian power system by fuel type at the beginning of the year 1993 is shown in Table 5.3. Tables 5.4, 5.5 and 5.6 give information on existing thermal units, hydro plants and rehabilitation program.

Table 5.3: Fixed System Summary of Dependable Capacities (MW)

	Hydroelectric (MW)	Thermal (MW) Fuel Type					
Year	Cap	Coal	Lignite	Foil	NGAS	Nuclear	Total
1993	1600	1940	1990	510	580	3400	10020
1994	2032	1940	1910	510	580	3400	9940
1995	2464	1915	1985	510	580	3400	9900
1996	2464	1915	1865	510	440	3400	9730
1997	2464	1750	1720	445	120	3400	9035
1998	2464	1750	1600	445	120	3400	8915
1999	2464	1555	1600	445	120	3400	8720
2000	2464	1165	1600	400	120	3400	8285
2004	2464	985	1600	400	120	3400	8105
2005	2464	625	1600	400	120	3000	7345
2006	2464	625	1600	400	120	2600	6945
2009	2464	430	1405	400	120	2600	6555
2010	2464	40	1210	400	120	2600	5970

Table 5.4: Existing Plants

	Name	Capacity Min Load	Capacity Max. Cap	Heat Rate Min Load	Heat Rate Full Load	Fuel Type	Fuel $/MMB	O & M Var. $/MWh	O & M Fixed $kW/m	Full FOR %	Main Days
ME21	Maritza E2, UN1	50	120	14959	11912	LIGN	0.63	3.13	0	2	44
ME22	Maritza E2, UN2	50	120	14094	12376	LIGN	0.63	3.13	0	2	44
ME23	Maritza E2, UN3	50	120	12876	11602	LIGN	0.63	3.13	0	2	44
ME24	Maritza E2, UN4	50	120	13979	12807	LIGN	0.63	3.13	0	2	44
MF25	Maritza E2, UN5	140	195	12805	11471	LIGN	0.63	3.13	0	2	44
M326	Maritza E2, UN6	140	195	12463	11253	LIGN	0.63	3.13	0	2	44
ME27	Maritza E2, UN7	140	195	11079	10483	LIGN	0.63	3.13	0	2	44
ME28	Maritza E2, UN8	140	195	11079	10483	LIGN	0.63	2.78	0	5	44
ME31	Maritza E3, UN1	140	195	11797	10968	LIGN	0.63	2.51	0	4	44
ME32	Maritza E3, UN2	140	195	11412	10849	LIGN	0.63	2.51	0	4	44
ME33	Maritza E3, UN3	140	195	10987	10571	LIGN	0.63	2.51	0	7	44
ME34	Maritza E3, UN4	140	195	11404	10737	LIGN	0.63	2.51	0	3	44
VAR1	VARNA UNIT 1	140	195	10150	9694	COAL	1.61	1.46	0	5	54
VAR2	VARNA UNIT 2	140	195	10301	9618	COAL	1.61	1.46	0	9	54
VAR3	VARNA UNIT 3	140	195	9932	9444	COAL	1.61	1.46	0	7	54
VAR4	VARNA UNIT 4	140	195	10404	9670	COAL	1.61	1.46	0	6	54
VAR5	VARNA UNIT 5	140	195	10606	9769	COAL	1.61	1.46	0	5	54
VAR6	VARNA UNIT 6	140	195	10612	9682	COAL	1.61	1.46	0	3	54
BBV1	BOBOV DOL UNIT 1	140	180	10924	9924	COAL	1.97	3.64	0	8	44
BBV2	BOBOV DOL UNIT 2	140	180	11126	10380	COAL	1.97	3.64	0	7	44
BBV3	BOBOV DOL UNIT 3	140	180	10602	[illegible]055	COAL	1.97	3.64	0	10	44
DHLI	DIST HTG - LIG		120		11097	LIGN	0.63	5.73	0	4	32
DHNG	DIST HTG - GAS		260		7858	MGAS	4	6.68	0	7	24
DHCO	DIST HTG - COAL		65		10262	COAL	1.97	7.86	0	9	35
DH01	DIST HTG - OIL		45		6298	HFO	2.51	6.19	0	3	19
INLI	INDUSTRY - LIG		25		5989	LIGN	0.63	6.94	0	25.4	30
INNG	INDUSTRY - GAS		320		6078	NGAS	4	1.94	0	25.4	30
INCO	INDUSTRY - COAL		165		6942	COAL	1.61	6.94	0	25.4	30
INO1	INDUSTRY - OIL		65		6758	HFO	2.51	2.5	0	25.4	30
KOZ1	KOZLODUY UNIT 1	350	400	11507	11420	NUCL	0.45	0	0.71	5	183
KOZ2	KOZLODUY UNIT 2	350	400	11507	11420	NUCL	0.45	0	0.71	3	58
KOZ3	KOZLODUY UNIT 3	350	400	11507	11420	NUCL	0.45	0	0.71	29	29
KOZ4	KOZLODUY UNIT 4	350	400	11507	11420	NUCL	0.63	0	0.71	3	58
KOZ5	KOZLODUY UNIT 5	840	900	11507	11452	NUCL	0.62	0	0.35	51	92
KOZ6	KOZLUDOY UNIT 6	840	900	11507	11452	NUCL	0		0.35	27	91
EXIS	EXISTING PLANTS	15	1600			Hydro					
IMPT	450 MW IMPORTS	0	400								

Table 5.5: Generation of the Existing Hydro Plants Under Different Hydro Conditions

Hydrocondition 1 (25%)			Hydrocondition 2 (56%)			Hydrocondition 3 (19%)		
EA	EMIN	MWC	EA	EMIN	MWC	EA	EMIN	MWC
110	22	1600	130	29	1600	162	36	1600
110	22	1600	130	29	1600	162	36	1600
140	50	1600	160	58	1600	200	82	1600
178	58	1600	210	72	1600	262	96	1600
221	58	1600	260	72	1600	320	97	1600
238	137	1600	280	154	1600	350	151	1600
238	101	1600	281	108	1600	351	122	1600
221	65	1600	261	72	1600	326	86	1600
136	14	1600	160	22	1600	200	29	1600
145	11	1600	170	14	1600	212	29	1600
155	11	1600	180	14	1600	225	22	1600
170	14	1600	200	21	1600	250	29	1600

Table 5.6: Fixed System Thermal Additions and Retirements
(No. Sets Added 1993-2010)

No.	Name	94	95	96	97	98	99	0	1	2	3	4	5	6	7	8	9	10
3	MA21	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
4	MA22	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.
5	MA23	.	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.
6	MA24	.	.	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.
10	MA28	.	1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
11	MA31	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	-1	.
12	MA32	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	-1
15	VAR1	.	.	.	.	.	1	.	.	.	.	.	.	.	.	.	.	.
16	VAR2	.	.	.	.	.	.	-1	.	.	.	.	.	.	.	.	.	.
17	VAR3	.	.	.	.	.	.	-1	.	.	.	.	.	.	.	.	.	.
18	VAR4	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	1	-1
19	VAR5	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	-1
20	VAR6	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
21	BOB1	.	.	.	.	.	.	.	.	.	.	-1	.	.	.	.	.	.
22	BOB2	.	.	.	.	.	.	.	.	.	.	.	-1	.	.	.	.	.
23	BOB3	.	.	.	.	.	.	.	.	.	.	.	-1	.	.	.	.	.
30	DHLI	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
31	DHLP	1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
32	DHNG	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.
33	DHNP	.	.	1	-1	.	.	.	.	.	.	.	.	.	.	.	.	.
34	DHCO	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
35	DHCP	.	1	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.
36	DHOI	.	.	.	.	.	.	-1	.	.	.	.	.	.	.	.	.	.
37	INLI	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.
38	INNG	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.
39	INCO	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.
40	INOI	.	.	-1	.	.	.	.	.	.	.	.	.	.	.	.	.	.

8. Candidate Units: The candidate units are defined as those units that are not currently firmly committed and that could be added to the generation system before the end of the planning horizon. The generation system expansion path is optimized by selecting the least-cost solution obtained using the WASP model. The following were considered as candidate units: 120 MW gas fired combustion turbine plants, new hydro station (Gona Arda, Sreden Iskar, Srendna Vacha and Nikopol), rehabilitation of the thermal plant (Varna, Bobov Dol and Maritza East), rehabilitation/repowering of the district heating and industrial plant Sofia (units 6 and 7), Traicho Kostov, Russe (units 3-6), Shumen, Republika (units 3-5), Pleven, Plovdiv (units 2 and 3), Burgas, Devina, Kremistovtski, Vratsa and Stara Zagora. The characteristics of the candidates are given in Table 5.7. The district heating and industrial plants were combined in three equivalent group each with the code name: KRVS, BURG, DEVI and PLEV, REPU, TRAI, in order to overcome the software limitations.

Table 5.7: Variable System Summary Description of Thermal Plants												
Name	Min. Load (MW)	Capacity (MW)	Heat Rates (kcal/kWh)		Fuel Costs (cents/Gcal)		Fuel Type	Fast Spin Rese %	FOR %	Days Schl Main	O & M (Fix) $/KWM	O & M (Var.) $/MWh
			Base Load	Aver. Incr.	Domes.	Foreign						
GTPL	48	120	3960	2161	0.0	1000.0	3	2	4.0	28	1.50	2.00
IMPC	280	500	2310	2005	0.0	496.0	0	2	10.0	40	2.20	5.00
CCPL	225	450	1935	1421	0.0	1000.0	3	2	4.0	33	1.40	1.60
MARR	50	150	2945	2872	420.0	0.0	1	2	5.0	44	0.00	2.78
BOBR	140	200	2394	552	0.0	796.0	0	2	5.0	44	0.00	2.78
VARR	140	210	2394	558	0.0	640.0	0	2	5.0	54	0.00	2.78
KRVS	150	240	1610	1610	0.0	1590.0	3	2	25.0	30	0.00	6.94
BURG	280	500	1500	1500	0.0	1590.0	3	2	25.0	30	0.00	6.94
DEVI	60	160	1580	1580	0.0	1590.0	3	2	25.0	30	0.00	6.94
PLEV	45	95	2425	2425	0.0	1590.0	3	2	5.0	30	0.00	6.68
REPU	20	35	1500	1500	0.0	780.0	0	2	5.0	30	0.00	6.68
TRAI	50	140	2020	2020	0.0	1590.0	3	2	5.0	30	0.00	6.68
FLVI	80	160	3300	2900	420.0	0.0	1	2	10.0	30	3.36	4.12
NUCL	540	600	2900	2658	0.0	244.0	4	0	20.0	45	0.71	0.00

The details of the main thermal plants to be rehabilitated as well as district heating and industrial plants are given in Tables 5.8, 5.9 and 5.10. The characteristics of the hydro plants are presented in Table 5.11, while the investment costs are presented in Table 5.12.

9. <u>Discount Rate</u>. The discount rate used for this analysis was 10%. The use of this assumption for the long-term planning purpose has been agreed with COE and NEK.

10. <u>Cost of Unserved Energy</u>. The expected unserved energy is the probabilistically determined amount of yearly electricity demand that is not supplied because of generating deficiencies and/or shortages in basic energy suppliers. The cost of unserved energy is included in the WASP objective function as a way to consider explicitly cost/reliability trade-offs. Thus, if the unit cost of unserved energy is assumed to be zero, the least-cost expansion plan will follow the minimum allowable reserve margin. Conversely, if the cost per unit of unserved energy is assumed to be very high, the least-cost expansion plan tends to have relatively high reserve margins. In this study, the basic cost per unit of unserved energy is assumed to be represented as a function of the unserved energy. The reserve margin and reliability of the power system were not set in advance, but they were obtained as a result of the optimization anticipating the unserved energy cost given as $c = a_1 + a_2 E^u + a_3 * (E_u/E_t)^2$, where Et is total generated energy, and E_t is unserved energy. The coefficients were determined as: $a_1 = 0.30$ \$/kWh, $a_2 = 0$, $a_3 = 0$.

Table 5.8: Main Power Plants Characteristics After Refurbishment/Rehabilitation

Plant	Retire Year	Rehab Year	Power After Rehab Gross MW	Minimum Gross MW	Gross Heat Rate @ Max kcal/kWh	Gross Heat Rate @ Min kcal/kWh	Gross Heat Rate @ Max btu/kWh	Gross Heat Rate @ Min btu/kWh	Increase In Output MW	Increase In Heat Rate btu/kWh	Forced Outage %	Sched. Maint. Days	Var O&M Lev/kWh	Var O&M $/MWh	Rehab Cost $/kW
Maritza East 2															
Unit 1	2010	1995	150	50	2896	2944	11491	11682	30.0	420.6	5	44	0.1	2.778	141
Unit 2	2011	1996	150	50	2896	2944	11491	11682	30.0	684.9	5	44	0.1	2.778	141
Unit 3	2012	1997	150	50	2896	2944	11491	11682	30.0	111.1	5	44	0.1	2.778	141
Unit 4	2013	1998	150	50	2896	2944	11491	11682	30.0	595.2	5	44	0.1	2.778	141
Unit 5	2014														
Unit 6	2015														
Unit 7	2016														
Unit 8	2022														
Maritza East 3															
Unit 1	2008														
Unit 2	2009														
Unit 3	2010														
Unit 4	2011														
Varna															
Unit 1	2010	1995	210	140	2333	2394	9257	9499	0.0	436.5	5	54	0.1	2.778	221
Unit 2	2010	1995	210	140	2333	2394	9257	9499	0.0	381.1	5	54	0.1	2.778	221
Unit 3	2010	1995	210	140	2333	2394	9257	9499	0.0	186.5	5	54	0.1	2.778	221
Unit 4	2011	1996	210	140	2333	2394	9257	9499	0.0	412.7	5	54	0.1	2.778	141
Unit 5	2011	1996	210	140	2333	2394	9257	9499	0.0	511.9	5	54	0.1	2.778	141
Unit 6	2012	1997	210	140	2333	2394	9257	9499	0.0	424.6	5	54	0.1	2.778	141
Bobov Dol															
Unit 1	2009	1994	200	140	2333	2394	9257	9499	20.0	666.6	5	44	0.1	2.778	173
Unit 2	2010	1995	200	140	2333	2394	9257	9499	20.0	1122.9	5	44	0.1	2.778	173
Unit 3	2011	1996	200	140	2333	2394	9257	9499	20.0	797.6	5	44	0.1	2.778	173

Table 5.9: District Heating Plant Rehabilitation/Repowering Option

District Heating Plant	Retirement Year	Rehab Year	Power O/P After Rehab (MW)	Increase in MW	Heat Rate After Rehab (Btu/kWh)	Rehab Cost $/kW	Rehab Cost $ mill.
Maritza East 1							
Unit 1	1995						
Unit 2	1996						
Unit 3	1998						
Unit 4	1997						
Maritza 3							
Unit 2	1993						
Unit 3	2000						
Sofia							
Unit 4	1994						
Unit 5	1994						
Unit 6	2010	1995	144	99	6103	300	43.2
Unit 7	2011	1996	240	220	6198	300	72.0
Traicho Kostov							
Unit 1	2010	1995	142	122	5619	275	39.1
Unit 2	2010	1995	142	122	5619	275	39.1
Unit 3	2011	1996	142	122	5619	275	39.1
Unit 4	2011	1996	142	122	5619	275	39.1
Unit 5	2011	1996	312	257	5797	275	85.8
Russe							
Unit 1	1998						
Unit 2	2000						
Unit 3	2010	1995	110	25	9361	225	24.8
Unit 4	2011	1996	110	25	9361	225	24.8
Unit 5	2013	1998	60	10	8341	315	18.9
Unit 6	2015	2000	60	10	8341	315	18.9
Shumen							
Unit 1	2010	1995	54	50	5718	482	26.0
Unit 2	2011	1996	82	78	5458	488	40.0
Unit 3	2011	1996	46	42	6055	472	21.7
Republica							
Unit 2	1993						
Unit 3	2009	1994	30	10	5952	50	1.5
Unit 4	2009	1994	25	5	5952	50	1.3
Unit 5	2010	1995	55	15	5952	50	2.8
Unit 6	2026						
Russe West							
Unit 1	2002						
Av Stoianov							
Unit 1	2005						
Kazanlak							
Unit 1	2004						
Unit 2	2005						
Pleven							
Unit 1	2012	1997	83	75	9456	466	38.7
Unit 2	2012	1997	94	86	9626	473	44.5
Unit 3	2013	1998	118	110	9888	486	57.3
Gabrovo							
Unit 1	1999						
Unit 2	2008						
Unit 3	2013						
Plovdiv							
Unit 1	2005						
Unit 2	2011	1995	119	99	8773	308	36.7
Unit 3	2009	1994	142	122	8769	275	9.1

TABLE 5.10: INDUSTRIAL PLANT REHABILITATION/REPOWERING OPTIONS							
INDUSTRIAL PLANTS	RETIREMENT YEAR	REHAB YEAR	POWER O/P AFTER REHAB MW	INCREASE IN MW	HEAT RATE AFTER REHAB BTU/KWh	REHAB COST $/KW	REHAB COST $ MIL
Burgas							
Unit 1	2012	1997	498	398	7242	300	149.4
Unit 2	2012	1997	584	524	6035	289	168.8
Devnia							
Unit 2	2010	1995	332	292	4972	340	112.9
Unit 3	2011	1996	162	152	5400	344	55.7
Unit 4	2011	1996	122	112	5511	357	43.6
Kremikovtsi							
Unit 1							
Unit 2	2013	1998	238	198	6047	306	72.8
Unit 3	2013	1998	238	228	4877	307	73.1
Vratsa	2013	1998	284	[illegible]	3619	274	77.8
Stara Zagora							84.0
Unit 2	2013	1998	236	224	5698	356	

11. Fuel Prices. The prices of the fossil and nuclear fuel which was assumed in the analysis are presented in Table 5.13.

Table 5:13 Fossil and Nuclear Fuel Prices			
Fuel Type	$/Gcal	$/t	kcal/kg
Lignite			
Maritza East	4.20	6.3	1500
Coal			
Varna	6.40	35	5500
Bobov Dol	7.80	43	5500
Imported Coal (other)	4.96	43	6690
Natural Gas	15.90	127	8000
Fuel Oil	10.00	96	9600
Nuclear			
Kozloduy 1-4	1.79		
Kozloduy 5 & 6	2.44		

* $/k*m^3, kcal/m^3 ** $/ton.

Table 5.11 HYDRO CANDIDATES CHARACTERISTICS

	Hydro Condition 1 Probability = 0.25			Hydro Condition 2 Probability = 0.56			Hydro Condition 3 Probability = 0.19		
	EA	EMIN	CAP.	EA	EMIN	CAP.	EA	EMIN	CAP.
Srenden Iskar	11	5	44	13	7	44	14	7	44
P = 44 MWe	11	5	44	13	7	44	14	7	44
Earliest Generation	14	7	44	16	8	44	17	9	44
Date 1998	18	9	44	22	11	44	23	11	44
	23	11	44	28	13	44	28	14	44
	24	12	44	29	14	44	30	15	44
	24	12	44	29	14	44	30	15	44
	23	11	44	26	13	44	28	14	44
	14	7	44	16	8	44	17	8	44
	15	7	44	17	8	44	18	9	44
	16	8	44	18	9	44	19	10	44
	17	9	44	21	10	44	22	11	44
Sredna Vacha	11	0	120	13	0	120	14	0	120
P = 120 MWe	11	0	120	13	0	120	14	0	120
Earliest Generation	14	0	120	16	0	120	17	0	120
Date 1998	18	0	120	21	0	120	22	0	120
	22	0	120	26	0	120	27	0	120
	24	0	120	28	0	120	30	0	120
	24	0	120	28	0	120	30	0	120
	22	0	120	26	0	120	28	0	120
	13	0	120	13	0	120	17	0	120
	14	0	120	17	0	120	18	0	120
	15	0	120	18	0	120	19	0	120
	17	0	120	20	0	120	21	0	120
Gorna Arda	22	7	156	26	8	156	28	8	156
P = 156 MWe	22	7	156	26	8	156	28	8	156
Earliest Generation	28	8	156	32	10	156	34	10	156
Date 2000	36	11	156	42	13	156	44	13	156
	44	13	156	52	16	156	54	16	156
	48	14	156	56	17	156	60	18	156
	48	14	156	56	17	156	60	18	156
	44	13	156	53	16	156	56	17	156
	26	8	156	33	10	156	34	10	156
	28	8	156	34	10	156	36	11	156
	30	9	156	36	11	156	38	11	156
	34	10	156	40	12	156	42	13	156
Nikopol	90	57	400	108	57	400	113	57	400
P = 400 MWe	90	57	400	108	57	400	113	57	400
Earliest Generation	116	57	400	132	57	400	140	57	400
Date 2001	146	57	400	174	57	400	183	57	400
	182	57	400	214	57	400	225	57	400
	197	57	400	210	57	400	225	57	400
	197	57	400	210	57	400	225	57	400
	182	57	400	200	57	400	210	57	400
	112	57	400	132	57	400	140	57	400
	121	57	400	140	57	400	147	57	400
	126	57	400	148	57	400	155	57	400
	141	57	400	166	57	400	174	57	400

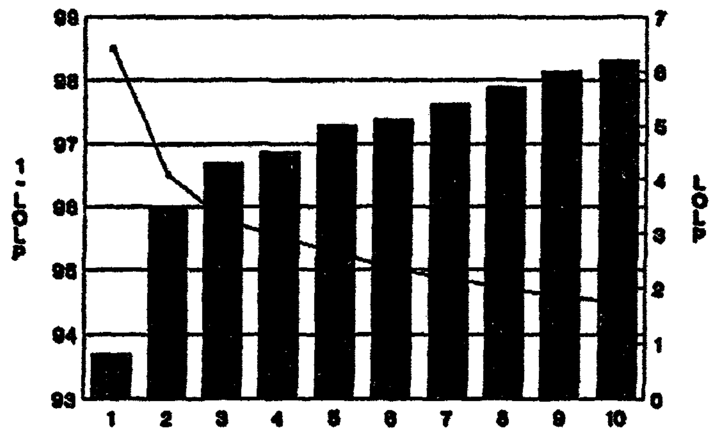
EA = Energy inflow
EMIN = Energy must be Released
CAP. = Depleatable Energy

Table 5.12 SUMMARY OF THE CAPITAL COSTS OF ALTERNATIVES

Plant	Capital Costs (Depreciable Part)			Inclusive IDC %	Constr. Time (Years)	Plant Life (Years)
	Domestic	Foreign	Total			
Thermal Plant Capital Costs						
Combustion Turbine	147.60	221.40	369.00	11.92	3	20
Imported Coal	594.00	891.00	1485.00	19.21	5	30
Combined Cycle	294.40	426.70	721.10	15.03	4	25
Maritsa	62.10	93.20	155.30	8.08	2	15
Bobov Dol	72.20	108.20	180.40	8.08	2	15
Varna	78.00	117.00	195.00	10.02	2	15
Kremikovtsi	127.60	191.50	319.10	10.02	3	15
Burgas	125.10	187.70	312.80	10.02	3	15
Devina	146.00	219.00	365.00	10.02	3	15
Pleven	211.10	316.70	527.80	10.02	3	15
Republica	22.20	33.30	55.50	8.08	2	15
Traicho Kostov	133.30	200.00	333.30	10.02	3	15
Fluidized Bed	578.00	867.00	1445.00	10.02	2.50	25.00
Nuclear	1035.50	1551.80	2586.30	22.67	6.00	30.00
Hydro Plant Capital Costs						
Srden Iskar	428.20	642.30	1070.50	8.08	2	50
Gorna Arda	221.90	332.80	554.70	22.67	6	50
Sredna Vacha	219.30	328.90	548.20	22.67	6	50
Nikopol	583.80	875.70	1459.50	26.00	7	50

12. Reliability (System LOLP). The system reserve margin and reliability are very often given as constraints of the system optimization. In our approach, the price of unserved energy was given at the outset so that the system reserve margin was obtained as a result of the optimization and is consistent with economically optimal levels of the reserve margin. A weak point of this approach is that the price of the unserved energy cannot be precisely determined. In order to provide a better approximation, an additional analysis has been done so as to obtain functional relations between long run marginal cost, unserved energy price and system reliability (reserve margin). The system was optimized with unserved energy price equal to N*LRMC, N = 1, 000, 10, so as to obtain the system reliability level. The results are presented in Figure 5.2. High price of unserved energy will request very high additional investment and would have little incremental contribution to reliability of the system. The economically optimal system reliability as shown by the result presented on Figure 5.2, is at around LOLP value of 3%.

Fig 5.2
Optimal Reliability vs Unserved Energy



13. Least-Cost Expansion Plans. The resulting least-cost solutions for the eighteen cases (three demand forecasts and six nuclear scenarios) for two different options (high and low repowering of cogeneration plants) have been obtained using WASP[1] computer program. Hydro power plants generation has been represented by three hydro conditions. A special modification of the load duration curves has been done in order to represent Chaira pumped storage plant operation. The main results and conclusions have been already presented in main parts of the report. In this annex, some of the most important results and analysis are going to be presented in more detail in the form of tables and figures. Tables 5.14 - 5.16 present generations of different generation unit types (hydro, thermal, nuclear, district heating and industrial plants) over the period 1993 - 2010 for the scenarios 1, 3 & 4 (low, moderate and high nuclear scenarios). The generation of all hydro units corresponds to the average hydrological and plant availability conditions. The possible annual variations are taken into account but not presented. Tables 5.17 - 5.19 presents average annual fuel requirements. The Tables 5.20 - 5.22 give the breakdown of the total costs in the period 1993 - 2010, as well as present values of the total system costs. These tables are followed by the Tables 5.23 - 5.25 which show the least-cost plan generation plants commissioning dates. Following these tables are the Tables 5.26 - 5.34 with generation of the individual generation plants in the period 1993 -2010. The Figures 5.3 - 5.5 illustrates the capacity development for three different demand forecast and scenarios O and 5. The last three Tables represents the breakdown of the total system costs for the low repowering option (limited gas) in the period 1993 -2010 (Tables 5.35 - 5.37).

1/ Wien Automatic System Planning Package (WASP), a Computer Code for Power Generation System Expansion Planning.

TABLE - 5.14 ENERGY GENERATION BY TYPE OF PLANT (GWh)

MINIMUM DEMAND FORECAST

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	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SCENERIO 1 (Low Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	3157.1	3157.1
THERMAL	21852	20884.5	20920.1	21859.0	22843.4	23650.1	24633.9	24002.4	24924.6	25753.8	25988.5	26388.9	26280.1	27219.3	27401.2	27439.2	25625.5	25062.94
NUCLEAR	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.07	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.07	9752.06	9752.06
DISTRICT	957.46	376.46	180.84	289.25	505.18	848.04	922.66	958.59	892.81	787.27	818.27	736.44	673.07	512.38	558.56	615.45	856.17	968.39
INDUSTRY	1206.27	871.09	360.19	5.26	4.66	55.72	193.09	1260.91	787.89	447.05	566.2	647.56	1395.77	824.13	993.31	1287.27	2887.02	3604.6
TOTAL	36212.9	34329.2	33658.3	34350.7	35550.4	36751.0	37946.9	38658.8	39042.1	39424.9	39809.8	40209.7	40785.8	40992.7	41389.9	41778.8	42277.9	42545.09
SCEN'RIO 3 (Moderate Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	3157.1	3157.1
THERMAL	12480.8	10624.4	9970.71	10784.0	11975.8	23650.1	24633.9	24002.4	24924.6	25753.8	25988.5	26388.9	26280.1	27219.3	27401.2	27439.2	25625.5	25062.94
NUCLEAR	21084.1	21111.2	21095.2	21127.1	21136.9	9752.06	9752.07	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.06	9752.07	9752.06	9752.06
DISTRICT	56.11	1.31	1.21	3.14	2.49	848.04	922.66	958.59	892.81	787.27	818.27	736.44	673.07	512.38	558.56	615.45	856.17	968.39
INDUSTRY	148.45	150.26	149.59	6.05	4.71	55.72	193.09	1260.91	787.89	447.05	566.2	647.56	1395.77	824.13	993.31	1287.27	2887.02	3604.6
TOTAL	36213.6	34332.4	33661.8	34365.4	35565.1	36751.0	37946.9	38658.8	39042.1	39424.9	39809.8	40209.7	40785.8	40992.7	41389.9	41778.8	42277.9	42545.09
SCENERIO 4 (High Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	3157.1
THERMAL	12480.8	10624.4	9970.71	10784.0	11975.8	19096.3	20143.2	20515.2	21037.0	21532.0	21888.2	22381.4	22997.8	23368.6	23726.0	24031.2	23506.7	21070.71
NUCLEAR	21084.1	21111.2	21095.2	21127.1	21136.9	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.68
DISTRICT	56.11	1.31	1.21	3.14	2.49	135.01	278.61	568.57	476.75	364.64	393.83	300.78	196.09	94.5	125.94	181.25	495.96	744.64
INDUSTRY	148.45	150.26	149.69	6.05	4.71	16.36	20.41	71.28	25.01	23.8	22.38	21.54	85.72	22.97	30.8	60.47	767.61	2507.11
TOTAL	36213.6	34332.4	33661.8	34365.4	35565.1	36759.5	37954.0	38666.8	39049.6	39432.2	39816.2	40215.5	40791.4	40997.9	41394.5	41784.7	42282.0	42546.24

TABLE – 5.15 ENERGY GENERATION BY TYPE OF PLANT (GWh)

MEDIUM DEMAND FORECAST

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SCENERIO 1 (Low Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3392.7
THERMAL	23226.3	23968.4	26316.9	27516.9	29792.1	29738.9	30167.0	28414.7	29632.7	31007.2	31151.9	31461.5	30716.7	32078.6	32151.2	32192.9	32771.3	32047.25
NUCLEAR	9752.06	9752.06	9752.08	9752.06	9752.07	9752.07	9752.06	9752.06	9752.06	9752.07	9752.06	9752.06	9752.06	9752.06	9752.08	9752.06	9752.07	9752.06
DISTRICT	1227.87	717.06	813.32	899.3	1132.71	1247.98	1302.42	1064.18	1038.89	1032.76	1045.88	1027.93	996.62	973.25	992.92	1008.03	1001.5	1088.62
INDUSTRY	2227.05	2425.62	2087.95	1867.98	567.15	1375.09	2072.28	3819.41	3252.44	2443.04	2848.93	3201.55	4605.49	3842.32	4390.01	4893.49	5087.87	5905.5
TOTAL	38878.4	39308.3	41415.4	42481.4	43689.2	44798.8	45978.5	46207.5	46833.2	47392.2	47955.9	48600.1	49226.9	49803.3	50443.3	51003.6	51769.8	52196.13
SCENERIO 3 (Moderate Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2446.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3392.7
THERMAL	14906.4	15496.3	17529.3	18739.2	19844.3	27408.2	27701.0	28414.7	29632.7	31007.2	31151.9	31461.5	30716.7	32078.6	32151.2	32192.9	32771.3	32047.25
NUCLEAR	21121.5	21139.3	21139.8	21139.8	21139.8	9752.06	9752.06	9752.06	9752.06	9752.07	9752.06	9752.06	9752.06	9752.06	9752.08	9752.06	9752.07	9752.06
DISTRICT	223.14	69.82	90.72	179.36	261.94	1397.62	1412.15	1064.18	1038.89	1032.76	1045.88	1027.93	996.62	973.25	992.92	1008.03	1001.5	1088.82
INDUSTRY	189.35	171.7	214.56	5.72	5.06	3542.75	4422.05	3819.41	3252.44	2443.04	2848.93	3201.55	4605.49	3842.32	4390.01	4893.49	5087.87	5905.5
TOTAL	38885.6	39312.3	41419.6	42509.3	43696.3	44785.4	45972.0	46207.5	46833.2	47392.2	47955.9	48600.1	49226.9	49803.3	50443.3	51003.6	51769.8	52186.13
SCENERIO 4 (High Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
THERMAL	14906.4	15496.3	17529.3	18739.2	19844.3	25320.2	25923.2	24308.6	25426.6	26497.5	26726.9	27145.9	26784.1	28004.8	28167.8	28337.9	28863.2	28291.52
NUCLEAR	21121.5	21139.3	21139.8	21139.8	21139.8	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.66
DISTRICT	223.14	69.82	90.72	179.36	261.94	1039.05	1102.19	984.48	928.06	898	921.58	881.46	830.83	760.14	804.99	862.72	890.34	945.69
INDUSTRY	189.35	171.7	214.56	5.72	5.06	690.54	1203.3	2694.35	2257.75	1775.6	2086.04	2351.48	3391.65	2817.24	3249.71	3584.88	3800.11	4727.78
TOTAL	38885.6	39312.3	41419.6	42509.3	43696.3	44801.2	45980.2	46211.2	46836.2	47394.9	47958.3	48602.6	49230.4	49805.9	50446.3	51009.3	51777.4	52188.73

TABLE - 5.16 ENERGY GENERATION BY TYPE OF PLANT (GWh)

MAXIMUM DEMAND FORECAST

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SCENERIO 1 (Low Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3392.7	5294.72
THERMAL	23226.3	23968.4	26316.9	28398.9	30637.5	33846.8	35207.6	34359.6	35548.4	36860.4	37032.6	37501.5	37178.6	38278.2	38526.9	38533.2	36277.0	32210.21
NUCLEAR	9752.06	9752.06	9752.08	9752.07	9752.07	9752.06	9752.07	9752.06	9752.06	9752.06	9752.07	9752.06	9752.07	9752.06	9752.06	9752.06	9752.06	9752.06
DISTRICT	1227.87	717.06	813.32	1306.12	1255.81	889.29	1076.79	981.15	937.95	912.88	959.61	929.43	906.36	834.86	887.24	899.24	1077.96	1565.65
INDUSTRY	2227.05	2425.62	2067.95	1429.62	1161.23	175.21	452.18	1962.49	1625.84	1343.24	1860.45	2250.27	3531.98	2885.42	3094.13	3444.22	5799.49	7757.85
TOTAL	38878.4	39308.3	41415.4	43331.8	45151.8	47107.5	49173.4	50212.4	51021.3	51825.7	52761.8	53590.4	54526.1	54907.7	55417.4	55785.8	56299.2	56580.49
SCENERIO 3 (Moderate Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3392.7	5294.72
THERMAL	14906.4	15496.3	17529.3	19618.8	21256.9	33846.8	35207.6	34359.6	35548.4	36860.4	37032.6	37501.5	37178.6	38278.2	38526.9	38533.2	36277.0	32210.21
NUCLEAR	21121.5	21139.3	21139.8	21139.8	21139.8	9752.06	9752.07	9752.06	9752.06	9752.06	9752.07	9752.06	9752.07	9752.06	9752.06	9752.06	9752.06	9752.06
DISTRICT	223.14	59.82	90.72	138.78	321.94	889.29	1076.79	981.15	937.95	912.88	959.61	929.43	906.36	834.86	887.24	899.24	1077.96	1565.65
INDUSTRY	189.35	171.7	214.56	11.56	10.62	175.21	452.18	1962.49	1625.84	1343.24	1860.45	2250.27	3531.98	2885.42	3094.13	3444.22	5799.49	7757.85
TOTAL	38885.6	39312.3	41419.6	43354.1	45174.4	47107.5	49173.4	50212.4	51021.3	51825.7	52761.8	53590.4	54526.1	54907.7	55417.4	55785.8	56299.2	56580.49
SCENERIO 4 (High Nuclear)																		
HYDRO	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3392.7
THERMAL	14906.4	15496.3	17529.3	19581.2	21299.0	26318.0	26996.3	25147.0	26406.3	27846.8	27986.4	31029.1	30491.5	31753.1	31964.8	31915.7	32506.6	31823.76
NUCLEAR	21121.5	21139.3	21139.8	21139.8	21139.8	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.6	15066.8	15066.6	15066.66
DISTRICT	223.14	59.82	90.72	173.06	280.18	1239.3	1303.45	1074.69	1059.5	1044.1	1064.22	968.69	943.93	903.93	953.62	951.81	944.93	1022.39
INDUSTRY	189.35	171.7	214.56	5.8	6.09	1788.36	3112.94	5727.6	5314.96	4098.67	5457.76	3374.97	4857.85	4022.34	4270.01	4684.95	4625.83	5273.32
TOTAL	38885.6	39312.3	41419.6	43345.1	45170.3	47097.1	49164.2	50173.0	51004.5	51813.3	52732.2	53586.5	54517.1	54903.1	55412.2	55776.2	56301.1	56578.83

TABLE - 5.17 FUEL REQUIREMENTS BY TYPE OF FUEL

MINIMUM DEMAND FORECAST

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		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SCENERIO 1 (Low Nuclear)																			
LIGNITE	(MILLION TON)	30.084	29.196	33.557	33.850	34.393	32.605	32.553	32.745	32.674	32.472	32.523	32.545	32.545	32.461	32.511	32.508	29.800	27.007
COAL	(MILLION TON)	3.776	3.271	2.085	2.322	2.675	3.454	3.807	3.649	3.911	4.147	4.253	4.295	4.116	4.427	4.508	4.540	4.407	3.435
NUCLEAR	(TON OF FUEL)	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500
N. GAS	(BILLION M**3)	0.039	0.003	0.000	0.001	0.000	0.009	0.034	0.222	0.138	0.078	0.099	0.113	0.246	0.145	0.175	0.226	0.511	1.304
F. OIL	(MILLION TON)	0.064	0.054	0.010	0.008	0.012	0.027	0.032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCENERIO 3 (Moderate Nuclear)																			
LIGNITE	(MILLION TON)	22.935	21.039	19.704	20.646	22.396	32.605	32.553	32.745	32.674	32.472	32.523	32.545	32.545	32.461	32.511	32.508	29.800	27.007
COAL	(MILLION TON)	0.627	0.177	0.086	0.192	0.328	3.454	3.807	3.649	3.911	4.147	4.253	4.295	4.116	4.427	4.508	4.540	4.407	3.435
NUCLEAR	(TON OF FUEL)	98.372	98.499	98.424	98.573	98.619	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500
N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.000	0.000	0.009	0.034	0.222	0.138	0.078	0.099	0.113	0.246	0.145	0.175	0.226	0.511	1.304
F. OIL	(MILLION TON)	0.000	0.000	0.000	0.000	0.000	0.027	0.032	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCENERIO 4 (High Nuclear)																			
LIGNITE	(MILLION TON)	22.935	21.039	19.704	20.646	22.396	31.200	30.720	31.229	30.530	29.937	30.170	30.373	30.488	30.642	30.814	30.985	28.832	26.484
COAL	(MILLION TON)	0.627	0.177	0.086	0.192	0.328	1.572	2.039	2.259	2.470	2.647	2.766	2.849	3.008	3.067	3.189	3.300	3.612	3.135
NUCLEAR	(TON OF FUEL)	98.372	98.499	98.424	98.573	98.619	70.296	70.297	70.297	70.297	70.296	70.296	70.296	70.296	70.297	70.296	70.296	70.296	70.297
N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.000	0.000	0.002	0.003	0.012	0.004	0.003	0.003	0.003	0.015	0.004	0.005	0.010	0.135	0.444
F. OIL	(MILLION TON)	0.000	0.000	0.000	0.000	0.000	0.001	0.008	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

TABLE - 5.18 FUEL REQUIREMENTS BY TYPE OF FUEL

MEDIUM DEMAND FORECAST

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SCENERIO 1 (Low Nuclear)																			
LIGNITE	(MILLION TON)	30.370	29.412	34.549	34.555	34.848	32.774	32.769	32.781	32.784	32.780	32.781	32.778	[illegible]	32.770	32.774	32.772	29.872	27.028
COAL	(MILLION TON)	4.459	4.805	4.640	4.838	4.520	4.867	4.922	4.149	4.578	5.059	5.116	5.150	4.697	5.246	5.258	5.261	4.684	3.460
NUCLEAR	(TON OF FUEL)	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500
N. GAS	(BILLION M**3)	0.143	0.145	0.105	0.265	0.711	0.898	1.042	1.391	1.280	1.133	1.212	1.261	1.470	1.332	1.429	1.515	2.257	3.145
F. OIL	(MILLION TON)	0.085	0.098	0.090	0.049	0.038	0.044	0.048	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCENERIO 3 (Moderate Nuclear)																			
LIGNITE	(MILLION TON)	25.531	26.443	29.614	28.908	31.398	32.772	32.767	32.781	32.784	32.780	32.781	32.778	32.774	32.770	32.774	32.772	29.872	27.028
COAL	(MILLION TON)	1.232	1.231	1.371	1.977	1.934	5.260	5.281	4.149	4.578	5.059	5.116	5.150	4.697	5.246	5.258	5.261	4.684	3.460
NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	98.632	98.632	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500
N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.000	0.000	0.579	0.770	1.391	1.280	1.133	1.212	1.261	1.470	1.332	1.429	1.515	2.257	3.145
F. OIL	(MILLION TON)	0.001	0.000	0.002	0.008	0.005	0.052	0.053	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCENERIO 4 (High Nuclear)																			
LIGNITE	(MILLION TON)	25.531	26.443	29.614	28.908	31.398	32.695	32.603	32.697	32.543	32.564	32.617	32.633	32.658	32.619	32.654	32.695	29.818	27.022
COAL	(MILLION TON)	1.232	1.231	1.371	1.977	1.934	4.244	4.431	3.809	4.185	4.505	4.607	4.666	4.355	4.802	4.878	4.959	4.560	3.433
NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	98.632	98.632	70.297	70.296	70.296	70.296	70.296	70.296	70.297	70.296	70.297	70.297	70.296	70.297	70.296
N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.000	0.000	0.121	0.212	0.477	0.399	0.313	0.368	0.416	0.599	0.499	0.575	0.630	1.281	2.151
F. OIL	(MILLION TON)	0.001	0.000	0.002	0.008	0.005	0.034	0.040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

TABLE – 5.19 FUEL REQUIREMENTS BY TYPE OF FUEL

MAXIMUM DEMAND FORECAST

page F-3 of 3

		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
SCENERIO 1 (Low Nuclear)																			
LIGNITE	(MILLION TON)	30.370	29.412	34.549	36.807	34.860	32.781	32.777	32.779	32.778	32.779	32.779	32.780	32.779	32.781	32.780	32.779	29.872	27.028
COAL	(MILLION TON)	4.459	4.805	4.640	4.861	4.814	4.099	4.381	3.829	4.273	4.678	4.789	4.931	4.684	5.228	5.241	5.245	4.688	3.475
NUCLEAR	(TON OF FUEL)	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500
N. GAS	(BILLION M**3)	0.143	0.145	0.105	0.200	0.818	1.875	2.050	2.463	2.373	2.294	2.421	2.463	2.662	2.479	2.568	2.625	3.121	3.553
F. OIL	(MILLION TON)	0.085	0.098	0.090	0.047	0.045	0.026	0.034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCENERIO 3 (Moderate Nuclear)																			
LIGNITE	(MILLION TON)	25.531	26.443	29.614	32.752	33.689	32.781	32.777	32.779	32.779	32.779	32.779	32.780	32.779	32.781	32.780	32.779	29.872	27.028
COAL	(MILLION TON)	1.232	1.231	1.371	1.530	2.079	4.099	4.381	3.829	4.273	4.678	4.789	4.931	4.684	5.228	5.241	5.245	4.688	3.475
NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	98.632	98.632	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500
N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.001	0.001	1.875	2.050	2.463	2.373	2.294	2.421	2.463	2.662	2.479	2.566	2.625	3.121	3.553
F. OIL	(MILLION TON)	0.001	0.000	0.002	0.003	0.007	0.026	0.034	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCENERIO 4 (High Nuclear)																			
LIGNITE	(MILLION TON)	25.531	26.443	29.614	31.076	33.703	32.736	32.736	32.777	32.754	32.774	32.777	32.757	32.759	32.748	32.758	32.753	29.867	27.029
COAL	(MILLION TON)	1.232	1.231	1.371	1.884	2.083	4.731	4.938	4.210	4.633	5.129	5.199	5.002	4.639	5.160	5.213	5.207	4.657	3.448
NUCLEAR	(TON OF FUEL)	98.547	98.630	98.632	98.632	98.632	70.297	70.297	70.296	70.297	70.297	70.297	70.296	70.297	70.296	70.296	70.296	70.296	70.296
N. GAS	(BILLION M**3)	0.000	0.000	0.000	0.000	0.000	0.300	0.551	0.963	0.901	0.806	0.921	1.259	1.476	1.322	1.379	1.438	2.128	2.985
F. OIL	(MILLION TON)	0.001	0.000	0.002	0.007	0.006	0.045	0.049	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

TABLE - 5.20 TOTAL SYSTEM COST
LOAD FORECAST - MINIMUM
USSM

SCENARIO 0

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	23.30	493.00	229.34	47.30	245.02	1037.96	1037.96
1994	16.30	499.66	254.59	234.60	42.60	1047.85	952.59
1995	11.70	541.68	200.19	273.80	2.33	1029.71	851.00
1996	11.70	529.49	254.22	203.20	14.36	1012.97	761.06
1997	11.70	593.05	273.61	265.70	13.46	1157.72	790 74
1998	0.00	606.52	290.58	152.20	14.42	1063.72	6[illegible].73
1999	0.00	619.62	310.16	18.30	13.61	961.69	542.79
2000	0.00	637.24	324.80	41.00	15.08	1018.12	522.45
2001	0.00	644.85	322.95	27.50	14.45	1009.75	471.06
2002	0.00	653.21	322.08	11.80	15.61	1002.70	425.24
2003	0.00	659.43	332.38	36.10	14.67	1042.58	401.96
2004	0.00	666.87	338.91	36.10	14.02	1055.90	370.09
2005	0.00	640.14	355.34	44.20	13.85	1053.53	336.69
2006	0.00	647.46	350.29	111.60	13.35	1122.70	325.20
2007	0.00	653.62	355.08	245.60	12.32	1267.62	333.86
2008	0.00	658.14	358.41	215.20	14.74	1246.76	298.47
2009	0.00	656.27	382.16	60.30	14.12	1112.85	242.19
2010	0.00	643.92	417.49	0.00	13.18	1074.59	212.60
TOTAL	74.70	11046.68	5255.26	2025.40	501.29	19320.84	9536.67

SCENARIO 1

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	35.00	393.76	129.69	20.30	0.19	578.96	578.96
1994	30.50	362.33	135.39	59.60	1.79	589.56	535.96
1995	37.50	339.63	132.92	46.90	2.04	560.99	463.63
1996	97.50	351.02	147.91	186.50	14.57	797.49	599.17
1997	117.50	368.38	151.01	273.10	13.58	923.56	630.81
1998	50.00	391.94	154.90	148.50	14.37	759.71	471.72
1999	35.00	406.96	160.81	45.10	13.42	661.29	373.28
2000	20.00	427.47	171.80	41.00	15.86	676.13	346.96
2001	20.00	422.19	170.54	27.50	15.00	655.22	305.67
2002	75.00	416.12	169.70	11.80	16.06	690.68	292.91
2003	20.00	425.54	171.41	39.40	15.03	671.39	258.85
2004	20.00	427.86	172.18	43.30	14.46	677.80	237.56
2005	20.00	436.41	175.92	44.50	14.53	691.36	220.29
2006	20.00	434.45	173.99	51.60	13.79	693.83	200.96
2007	20.00	441.71	175.80	110.90	12.77	761.17	200.44
2008	20.00	449.81	178.31	159.90	15.36	823.39	197.11
2009	20.00	467.92	192.42	60.30	14.10	754.73	164.25
2010	20.00	485.60	204.68	0.00	13.43	723.71	143.16
TOTAL	678.00	7451.13	2969.31	1372.20	220.33	12690.97	6221.78

SCENARIO 2

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	47.50	335.72	118.65	5.00	0.02	506.89	506.89
1994	54.30	307.39	127.78	27.60	1.55	518.62	471.47
1995	62.80	294.25	128.46	48.20	1.99	535.70	441.07
1996	113.50	303.99	142.03	203.10	14.10	777.02	583.79
1997	133.50	321.30	144.32	304.40	13.30	917.12	626.40
1998	57.50	391.94	154.90	148.50	14.37	767.21	476.38
1999	40.30	406.96	160.81	45.10	13.42	666.59	376.27
2000	23.80	427.47	171.80	41.00	15.86	679.93	348.91
2001	23.80	422.19	170.54	27.50	15.00	659.02	307.44
2002	78.80	416.12	169.70	11.80	16.06	694.48	294.63
2003	20.00	425.54	171.41	39.40	15.03	671.39	258.85
2004	20.00	427.86	172.18	43.30	14.46	677.80	237.56
2005	20.00	436.41	175.92	44.50	14.53	691.36	220.29
2006	20.00	434.45	173.99	51.60	13.79	693.83	200.96
2007	20.00	441.71	175.80	110.90	12.77	761.17	200.44
2008	20.00	449.81	178.31	159.90	15.36	823.39	197.11
2009	20.00	467.92	192.42	60.30	14.10	754.73	164.25
2010	20.00	485.60	204.68	0.00	13.43	723.71	143.18
TOTAL	796.40	7196.64	2931.69	1372.10	219.12	12517.95	6055.82

SCENARIO 3

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	60.00	280.86	110.31	5.00	0.01	456.19	456.19
1994	78.10	253.99	120.71	20.00	1.27	474.07	430.97
1995	86.10	243.74	118.72	31.90	1.57	484.03	400.02
1996	130.00	253.29	134.53	210.00	13.82	741.64	557.21
1997	150.00	268.70	137.29	321.40	13.18	890.56	608.27
1998	65.00	391.94	154.90	148.50	14.37	774.71	481.04
1999	45.50	406.96	160.81	45.10	13.42	671.79	379.21
2000	27.50	427.47	171.80	41.00	15.86	683.63	350.61
2001	27.50	422.19	170.54	27.50	15.00	662.72	309.17
2002	82.50	416.12	169.70	11.80	16.06	696.18	296.09
2003	20.00	425.54	171.41	39.40	15.03	671.39	258.85
2004	20.00	427.86	172.18	43.30	14.46	677.80	237.56
2005	20.00	436.41	175.92	44.50	14.53	691.36	220.29
2006	20.00	434.45	173.99	51.60	13.79	693.83	200.96
2007	20.00	441.71	175.80	110.90	12.77	761.17	200.44
2008	20.00	449.81	178.31	159.90	15.36	823.39	197.11
2009	20.00	467.92	192.42	60.30	14.10	754.73	164.25
2010	20.00	485.60	204.68	0.00	13.43	723.71	143.16
TOTAL	914.20	6938.58	2894.01	1372.10	218.01	12334.89	5891.63

SCENARIO 4

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	65.00	280.86	110.31	5.00	0.01	461.19	461.19
1994	63.10	253.99	117.71	20.00	1.27	456.07	414.61
1995	128.10	243.74	118.72	31.90	1.57	524.03	433.08
1996	160.00	253.29	134.53	210.00	13.82	771.64	579.75
1997	150.00	268.70	137.29	321.40	13.16	890.56	608.27
1998	77.50	335.47	147.45	133.00	13.85	707.26	439.15
1999	60.30	348.61	151.67	13.40	11.82	585.81	330.67
2000	43.50	362.51	155.77	41.00	16.63	619.72	318.01
2001	43.50	361.90	157.15	27.50	14.50	604.85	282.17
2002	98.60	362.11	158.16	11.80	15.27	646.17	274.04
2003	40.00	368.05	159.29	36.10	14.46	617.92	238.23
2004	40.00	371.86	43.26	39.40	[illegible]	508.61	176.23
2005	40.00	380.05	161.84	31.50	14.32	627.71	200.01
2006	40.00	382.70	162.46	20.30	13.47	618.94	179.28
2007	40.00	388.44	163.52	31.60	12.53	636.10	167.50
2008	40.00	394.17	164.75	34.60	15.07	648.58	155.27
2009	40.00	409.91	170.64	36.60	14.59	671.74	146.19
2010	40.00	420.77	186.71	0.00	13.35	660.83	130.74
TOTAL	1210.40	6187.15	2602.25	1045.10	212.71	11257.61	5536.39

SCENARIO 5

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	85.60	280.86	110.31	5.00	0.01	481.79	481.79
1994	150.60	253.99	117.71	20.00	1.27	543.57	494.16
1995	190.00	243.74	118.72	23.00	1.57	577.03	476.88
1996	165.00	262.47	135.17	169.20	11.71	733.55	551.13
1997	90.00	270.55	136.75	208.90	13.22	719.42	491.37
1998	75.00	287.30	139.12	72.00	12.47	585.89	363.79
1999	60.00	298.08	143.24	43.00	11.58	555.90	313.79
2000	60.00	306.61	145.45	73.50	15.27	602.83	309.36
2001	115.00	310.58	146.71	104.60	13.73	690.62	322.18
2002	60.00	313.93	148.05	95.90	14.27	632.15	268.09
2003	67.50	317.22	149.41	36.10	11.57	581.80	224.31
2004	65.30	322.07	150.79	36.10	11.27	585.52	205.22
2005	63.50	353.62	157.13	24.30	13.09	611.94	194.96
2006	63.60	382.77	162.47	0.00	13.13	622.16	180.22
2007	63.80	388.50	163.53	0.00	12.26	628.10	165.40
2008	63.80	394.32	164.77	15.40	14.88	653.15	156.36
2009	63.80	409.61	170.73	31.70	14.55	690.38	150.26
2010	63.80	429.99	184.57	0.00	13.96	692.33	136.97
TOTAL	1566.60	5818.21	2644.63	958.70	199.79	11188.13	5486.24

TABLE - 5.21 TOTAL SYSTEM COST
LOAD FORECAST - MEDIUM
US$M

SCENARIO 0

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	G.TOTAL	PV-EC.
1993	23.30	493.00	229.34	146.10	674.30	1566.03	1566.03
1994	16.30	499.66	254.59	418.40	732.47	1921.42	1746.74
1995	11.70	572.62	280.87	469.80	172.88	1487.87	1229.64
1996	11.70	601.58	298.32	352.70	319.84	1584.14	1190.19
1997	11.70	610.28	252.20	391.10	17.84	1283.11	876.36
1998	0.00	648.26	251.55	186.10	18.95	1104.86	686.03
1999	0.00	662.03	231.40	18.30	18.01	929.73	524.81
2000	0.00	672.65	257.36	41.00	19.88	990.89	508.48
2001	0.00	672.90	222.22	27.50	19.10	941.72	439.32
2002	0.00	670.59	246.20	29.50	20.73	967.02	410.11
2003	0.00	682.16	262.13	73.10	19.47	1036.86	396.90
2004	0.00	687.29	256.97	148.70	18.63	1111.59	389.61
2005	0.00	692.10	271.56	230.40	17.97	1212.03	386.19
2006	0.00	694.35	266.03	454.90	17.52	1432.80	415.03
2007	0.00	707.65	273.45	635.60	15.99	1632.69	429.94
2008	0.00	718.72	281.10	524.10	19.19	1543.11	369.41
2009	0.00	711.40	310.34	146.70	17.79	1186.23	256.16
2010	0.00	674.17	339.34	0.00	15.69	1029.20	203.62
TOTA	74.70	11671.41	4754.95	4294.00	2156.25	22951.31	12026.60

SCENARIO 1

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	35.00	438.71	148.00	47.30	2.13	671.13	671.13
1994	30.50	447.93	163.34	234.50	2.66	878.93	799.03
1995	87.50	466.67	166.48	273.80	3.40	947.85	783.35
1996	97.50	494.05	191.42	203.20	25.07	1011.24	759.76
1997	117.50	507.22	183.36	265.70	18.64	1092.43	746.14
1998	80.00	533.47	189.28	152.20	19.27	944.59	586.52
1999	35.00	552.63	196.76	18.30	17.75	820.44	463.12
2000	20.00	565.63	212.75	41.00	20.08	859.46	441.04
2001	20.00	584.57	211.04	27.50	18.97	842.08	392.84
2002	75.00	559.95	209.01	11.80	20.38	876.14	371.57
2003	20.00	572.58	212.44	36.10	19.23	860.35	331.70
2004	20.00	579.37	215.03	38.60	18.54	871.54	305.47
2005	20.00	586.54	224.78	49.70	19.07	900.08	286.79
2006	20.00	589.25	220.80	127.00	18.08	975.13	282.46
2007	20.00	602.21	226.83	272.60	17.13	1138.77	299.87
2008	20.00	613.36	232.74	253.40	21.32	1140.82	273.10
2009	20.00	636.29	242.23	85.10	21.31	1004.93	218.70
2010	20.00	652.67	262.14	0.00	21.21	956.02	189.14
TOTAL	678.00	9963.51	3708.42	2137.50	304.22	16791.95	8201.74

SCENARIO 2

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	47.50	300.43	131.99	19.10	0.02	499.04	499.04
1994	54.30	315.41	144.02	138.20	2.07	654.00	594.54
1995	62.80	334.03	149.90	195.00	2.98	744.71	615.46
1996	113.80	364.96	168.54	293.20	19.99	960.49	721.63
1997	133.80	382.74	175.49	239.60	18.70	950.33	649.09
1998	57.50	473.60	198.76	171.30	19.64	920.79	571.74
1999	40.30	476.78	204.80	145.90	18.45	885.23	499.69
2000	23.80	495.72	227.85	98.20	20.02	865.60	444.19
2001	23.80	499.75	222.26	54.50	18.88	819.20	382.16
2002	78.80	504.79	220.30	13.10	20.60	837.59	355.22
2003	20.00	514.08	223.59	36.10	19.31	813.08	313.48
2004	20.00	520.88	226.34	38.60	18.48	824.29	288.91
2005	20.00	525.81	236.08	49.70	18.25	849.84	270.79
2006	20.00	531.81	232.98	127.00	17.59	929.38	269.21
2007	20.00	543.05	236.69	270.70	16.32	1088.76	286.70
2008	20.00	552.91	243.65	220.80	19.83	1057.19	253.08
2009	20.00	582.80	253.73	64.00	19.03	939.56	204.46
2010	20.00	606.25	273.12	0.00	20.69	919.99	182.02
TOTA	796.4	8524.8	3772.1	2175.0	290.8	15569.1	7401.4

SCENARIO 3

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	60.00	318.13	116.70	12.60	0.01	507.43	507.43
1994	78.10	323.24	132.10	39.00	2.09	574.53	522.30
1995	88.10	348.03	137.55	49.80	3.00	626.49	517.76
1996	130.00	367.49	153.22	293.90	19.66	964.27	724.47
1997	150.00	380.83	158.54	240.50	18.11	1145.98	782.72
1998	65.00	544.92	202.30	280.80	22.24	1115.26	692.49
1999	45.50	569.23	206.20	78.60	18.34	917.87	518.11
2000	27.50	565.63	212.75	41.00	20.06	866.96	444.89
2001	27.50	584.57	211.04	27.50	18.97	849.58	396.34
2002	82.50	559.95	209.01	11.80	20.38	883.64	374.75
2003	20.00	572.58	212.44	36.10	19.23	860.35	331.70
2004	20.00	579.37	215.03	38.60	18.54	871.54	305.47
2005	20.00	586.54	224.78	49.70	19.07	900.08	286.79
2006	20.00	589.25	220.80	127.00	18.08	975.13	282.46
2007	20.00	602.21	226.83	272.60	17.13	1138.77	299.87
2008	20.00	613.36	232.74	253.40	21.32	1140.82	273.10
2009	20.00	636.29	242.23	85.10	21.31	1004.93	218.70
201C	20.00	652.67	262.14	0.00	21.21	956.02	189.14
TOTAL	914.20	9374.29	3574.41	2138.00	298.75	16299.65	7668.50

SCENARIO 4

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	65.00	318.13	116.70	12.60	0.01	512.43	512.43
1994	63.10	323.24	132.10	39.00	2.09	559.53	507.66
1995	128.10	348.03	137.55	47.40	3.00	664.09	548.83
1996	160.00	367.49	153.22	246.80	19.66	947.17	711.62
1997	150.00	380.83	158.54	352.00	18.11	1057.48	722.27
1998	77.50	467.24	173.63	152.20	19.25	889.82	552.51
1999	60.30	484.64	181.13	18.30	17.91	762.27	430.28
2000	43.80	495.59	195.12	41.00	19.80	795.32	408.19
2001	43.80	495.46	194.79	27.50	18.86	780.40	364.06
2002	98.80	492.42	194.18	11.80	20.42	817.57	346.73
2003	40.00	504.28	197.11	36.10	19.17	796.64	307.14
2004	40.00	511.46	199.23	36.10	18.43	805.21	282.22
2005	40.00	520.92	204.26	44.20	18.47	827.83	263.77
2006	40.00	524.19	203.05	111.80	17.68	896.46	259.67
2007	40.00	537.94	206.67	246.60	16.54	1047.34	275.80
2008	40.00	548.06	210.68	215.20	20.02	1033.95	247.52
2009	40.00	570.33	220.10	60.30	19.35	910.07	198.06
2010	40.00	589.31	237.81	0.00	20.42	887.54	175.59
TOTA	1210.40	8478.88	3314.00	1698.70	289.16	14991.14	7115.31

SCENARIO 5

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	85.60	318.13	116.70	12.60	0.01	533.04	533.04
1994	150.60	323.24	132.10	35.70	2.09	643.73	585.21
1995	190.00	348.03	137.56	32.50	3.00	711.08	587.67
1996	165.00	365.22	154.33	203.10	19.83	907.48	681.80
1997	90.00	384.50	156.14	304.40	18.14	953.18	651.03
1998	75.00	397.88	156.92	133.00	19.03	783.62	486.57
1999	60.00	410.38	164.04	13.40	17.51	665.33	375.56
2000	60.00	419.31	169.10	41.00	20.58	709.99	364.34
2001	115.00	421.83	170.17	27.50	19.55	754.04	351.77
2002	60.00	424.59	171.32	15.10	21.15	692.16	293.54
2003	67.50	434.14	173.38	58.70	19.92	753.64	290.56
2004	65.30	441.72	175.29	88.00	19.20	789.51	276.72
2005	63.80	485.21	188.91	75.80	18.89	832.60	265.29
2006	63.80	533.71	200.96	130.80	18.26	947.53	274.47
2007	63.80	546.51	205.19	251.50	17.04	1084.04	285.46
2008	63.80	547.75	210.59	215.20	19.72	1057.05	253.05
2009	63.80	570.24	218.90	60.30	18.97	933.21	203.09
2010	63.80	589.40	237.10	0.00	18.63	908.93	179.83
TOTAL	1566.80	7961.58	3141.70	1698.60	291.49	14660.17	6939.00

TABLE - 5.22 TOTAL SYSTEM COST
LOAD FORECAST - MAXIMUM
USSM

SCENARIO 0

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	23.30	493.00	229.34	149.10	674.30	1569.03	1569.03
1994	16.30	499.66	254.60	583.20	732.47	2086.22	1896.56
1995	11.70	658.66	257.70	693.50	303.62	1925.27	1508.48
1996	11.70	625.31	292.01	331.30	79.96	1340.28	1006.96
1997	11.70	644.14	226.69	235.50	19.46	1137.19	776.71
1998	0.00	691.52	242.54	194.80	20.68	1149.54	713.77
1999	0.00	727.34	264.36	142.90	19.29	1153.89	651.34
2000	0.00	749.04	308.96	220.00	32.71	1310.71	672.60
2001	0.00	753.84	304.05	129.10	22.29	1209.28	564.14
2002	0.00	756.82	299.48	36.90	22.10	1115.30	473.00
2003	0.00	735.54	303.00	59.70	19.18	1117.42	430.81
2004	0.00	746.81	308.81	92.10	16.52	1168.24	408.76
2005	0.00	757.17	330.69	187.00	27.93	1302.79	415.11
2006	0.00	758.52	318.53	409.30	17.88	1504.24	435.72
2007	0.00	769.33	324.55	531.30	16.93	1638.10	431.36
2008	0.00	775.96	331.33	345.60	19.49	1465.59	360.85
2009	0.00	769.58	357.07	94.40	16.29	1213.60	284.11
2010	0.00	768.33	393.11	0.00	16.86	1144.26	226.38
TOTA	74.70	12580.76	4963.41	4435.70	2085.84	24448.93	12795.73

SCENARIO 1

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	35.00	436.71	148.00	47.30	2.13	671.13	671.13
1994	30.50	447.93	163.14	283.30	2.66	927.53	843.21
1995	37.50	466.67	181.18	466.60	3.40	1155.36	964.64
1996	97.50	499.63	190.15	479.40	21.52	1288.10	967.77
1997	117.50	532.47	196.64	370.00	22.26	1237.86	845.48
1998	50.00	567.69	194.86	183.90	20.83	1017.28	631.65
1999	35.00	593.63	204.91	18.30	19.67	871.52	491.96
2000	20.00	619.44	221.61	41.00	22.14	924.20	474.26
2001	20.00	622.79	222.32	27.50	21.12	913.73	426.26
2002	75.00	625.89	223.24	11.50	22.97	958.90	406.67
2003	20.00	645.51	228.16	56.30	21.80	971.78	374.66
2004	20.00	656.73	231.39	76.00	21.07	1005.19	352.31
2005	20.00	671.44	239.64	146.80	21.65	1099.53	350.34
2006	20.00	671.73	236.61	146.80	20.44	1095.58	317.35
2007	20.00	680.72	239.45	223.10	19.04	1182.31	311.34
2008	20.00	688.75	242.77	197.30	22.83	1171.65	260.48
2009	20.00	711.27	268.72	88.40	24.04	1110.42	241.66
2010	20.00	705.99	302.04	0.00	20.54	1048.56	207.45
TOTAL	676.00	10646.89	3933.63	2861.80	330.10	18650.62	9148.81

SCENARIO 2

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	47.50	377.73	126.69	27.40	0.08	579.40	579.40
1994	54.30	384.64	140.87	211.50	2.23	793.54	721.40
1995	62.80	405.56	146.46	403.40	3.05	1021.27	844.02
1996	113.80	434.30	166.47	574.00	20.30	1308.87	983.38
1997	133.80	471.76	175.97	430.30	19.57	1231.41	841.07
1998	57.50	567.69	194.86	183.90	20.83	1024.78	636.31
1999	40.30	593.63	204.91	18.30	19.67	876.82	494.94
2000	23.80	619.44	221.61	41.00	22.14	928.00	476.21
2001	23.80	622.79	222.32	27.50	21.12	917.53	428.03
2002	78.80	625.89	223.24	11.50	22.97	962.70	408.28
2003	20.00	645.51	228.16	56.30	21.80	971.78	374.66
2004	20.00	656.73	231.39	76.00	21.07	1005.19	352.31
2005	20.00	671.44	239.64	146.80	21.65	1099.53	350.34
2006	20.00	671.73	236.61	146.80	20.44	1095.58	317.35
2007	20.00	680.72	239.45	223.10	19.04	1182.31	311.34
2008	20.00	688.75	242.77	197.30	22.83	1171.65	260.48
2009	20.00	711.27	268.72	88.40	24.04	1110.42	241.66
2010	20.00	705.99	302.04	0.00	20.54	1048.56	207.45
TOTA	796.40	10535.58	3812.19	2861.80	323.36	18329.34	8848.64

SCENARIO 3

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	60.00	318.13	116.70	19.10	0.01	513.94	513.94
1994	78.10	323.24	132.10	193.90	2.09	729.43	663.12
1995	88.10	348.03	137.55	410.90	3.00	987.58	816.19
1996	130.00	373.35	156.50	592.30	20.14	1272.29	955.89
1997	150.00	400.26	160.59	430.30	19.38	1160.53	792.66
1998	65.00	567.69	194.86	183.90	20.83	1032.28	640.96
1999	45.50	593.63	204.91	18.30	19.67	882.02	497.87
2000	27.50	619.44	221.61	41.00	22.14	931.70	476.11
2001	27.50	622.79	222.32	27.50	21.12	921.23	429.76
2002	82.50	625.89	223.24	11.80	22.97	966.40	409.85
2003	20.00	645.51	228.16	56.30	21.80	971.78	374.66
2004	20.00	656.73	231.39	76.00	21.07	1005.19	352.31
2005	20.00	671.44	239.64	146.80	21.65	1099.53	350.34
2006	20.00	671.73	236.61	146.80	20.44	1095.58	317.36
2007	20.00	680.72	239.45	223.10	19.04	1182.31	311.34
2008	20.00	688.75	242.77	197.30	22.83	1171.65	260.48
2009	20.00	711.27	268.72	88.40	24.04	1110.42	241.66
2010	20.00	705.99	302.04	0.00	20.54	1048.56	207.45
TOTAL	914.20	10224.56	3759.17	2861.70	322.76	18082.42	8633.95

SCENARIO 4

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	65.00	318.13	116.70	12.60	0.01	512.43	512.43
1994	63.10	323.24	132.10	46.60	2.09	567.13	515.57
1995	128.10	348.03	137.55	63.00	3.00	679.69	561.72
1996	160.00	376.72	155.74	239.20	20.20	951.86	715.14
1997	150.00	400.20	160.42	336.40	18.69	1065.70	727.89
1998	77.50	512.30	187.45	152.20	21.14	950.59	590.24
1999	60.30	552.39	196.84	18.30	19.71	849.55	479.55
2000	43.80	576.07	226.42	60.90	31.56	942.75	483.76
2001	43.80	582.44	226.91	119.20	23.88	996.23	464.75
2002	96.80	585.34	224.24	166.70	24.25	1096.33	466.22
2003	40.00	603.75	233.50	96.30	28.35	1001.90	386.26
2004	40.00	601.94	222.02	38.60	21.60	924.16	323.91
2005	40.00	613.81	235.04	49.70	23.53	962.08	306.56
2006	40.00	613.89	229.27	127.00	21.11	1031.27	298.72
2007	40.00	622.27	233.47	272.60	19.94	1188.28	312.91
2008	40.00	630.30	237.70	263.40	24.72	1196.11	283.95
2009	40.00	647.87	244.50	85.10	23.63	1041.10	226.57
2010	40.00	660.75	262.85	0.00	22.01	985.61	195.00
TOTA	1210.40	9571.44	3666.74	2137.80	349.39	16935.77	7851.19

SCENARIO 5

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	85.60	318.13	116.70	12.60	0.01	533.04	533.04
1994	150.60	323.24	132.10	43.30	2.09	651.33	592.12
1995	190.00	348.03	137.55	55.80	3.00	734.38	606.93
1996	165.00	374.67	156.74	203.50	20.41	920.32	691.45
1997	90.00	400.04	160.61	273.10	19.06	942.81	643.95
1998	75.00	434.54	165.70	148.50	20.87	844.61	524.44
1999	60.00	464.94	175.07	48.40	19.68	768.09	433.57
2000	60.00	491.70	187.61	48.20	22.96	810.67	416.00
2001	115.00	495.50	188.76	47.80	21.97	869.03	405.41
2002	60.00	500.84	190.40	63.40	23.88	838.52	355.62
2003	67.50	519.67	195.10	147.00	22.54	951.80	366.96
2004	65.30	530.93	196.27	195.90	21.70	1012.09	354.73
2005	63.80	580.77	228.39	104.40	22.01	999.37	318.43
2006	63.80	612.72	228.16	111.60	20.61	1036.90	300.36
2007	63.80	622.20	232.73	246.60	19.28	1184.59	311.94
2008	63.80	630.35	236.96	215.20	23.09	1169.39	279.94
2009	63.80	648.29	243.91	60.30	21.99	1038.29	225.96
2010	63.80	665.17	260.22	0.00	25.04	1014.22	200.66
TOTAL	1566.80	8961.74	3436.18	2025.60	330.15	16319.46	7581.49

TABLE - 5.23 OPTIMUM SOLUTION - MINIMUM
ANNUAL ADDITIONS (MW)

	SCENERIO 0			SCENERIO 1			SCENERIO 2			SCENERIO 3			SCENERIO 5			SCENERIO 5	
YEAR	PLANT NAME	CAP. (MW)	YEAR	PLANT NAME	CAP. (MW)	YEAR	PLANT NAME	CAP. (MW)	YEAR	PLANT NAME	CAP. (MW)	YEAR	PLANT NAME	CAP. (MW)	YEAR	PLANT NAME	CAP. (MW)
1993	—	—	1993	—	—	1993	—	—	1993	—	—	1993	—	—	1993	—	—
1994	—	—	1994	—	—	1994	—	—	1994	—	—	1994	—	—	1994	—	—
1995	Maritsa	300	1995	Maritsa	300	1995	—	—	1995	—	—	1995	—	—	1995	—	—
	Republica	35		—	—		—	—		—	—		—	—		—	—
1996	Maritsa	150	1996	Maritsa	150	1996	Maritsa	150	1996	—	—	1996	—	—	1996	—	—
	Burgas	500		Republica	35		—	—		—	—		—	—		—	—
1997	Combined Cycle	450	1997	Maritsa	150	1997	Maritsa	150	1997	Maritsa	150	1997	Maritsa	150	1997	—	—
	Maritsa	150		Republica	70		Republica	105		Republica	70		Republica	70		—	—
	Republica	70		—	—		—	—		—	—		—	—		—	—
1998	Burgas	600	1998	Burgas	1000	1998	Maritsa	300	1998	Maritsa	450	1998	Maritsa	450	1998	Maritsa	150
	Sreden Iskar (HYDA)	44		—	—		Burgas	1000		Burgas	1000		Burgas	1000		Burgas	1000
	—	—		—	—		—	—		Republica	35		Republica	35		Republica	35
1999	Varna	210	1999	Varna	210	1999	Varna	210	1999	Varna	210	1999	Varna	210	1999	Varna	210
	Devnia	640		Devnia	640		Devnia	640		Devnia	640		Devnia	640		Devnia	160
	—	—		—	—		—	—		—	—		—	—		Maritsa	150
2000	Goma Arda (HYDA)	156	2000	Sreden Iskar (HYDA)	44	2000	Sreden Iskar (HYDA)	44	2000	Sreden Iskar (HYDA)	44	2000	—	—	2000	—	—
2001	Varna	210	2001	Varna	210	2001	Varna	210	2001	Varna	210	2001	Varna	210	2001	Varna	210
	—	—		—	—		—	—		—	—		—	—		Devnia	160
2002	Varna	210	2002	Varna	210	2002	Varna	210	2002	Varna	210	2002	Varna	210	2002	Varna	210
	—	—		—	—		—	—		—	—		—	—		Republica	70
2003	—	—	2003	—	—	2003	—	—	2003	—	—	2003	—	—	2003	Maritsa	300
	—	—		—	—		—	—		—	—		—	—		Devnia	320
2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200
2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200
2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200
2007	—	—	2007	—	—	2007	—	—	2007	—	—	2007	—	—	2007	—	—
2008	—	—	2008	—	—	2008	—	—	2008	—	—	2008	—	—	2008	—	—
2009	Combined Cycle	450	2009	Goma Arda (HYDA)	156	2009	Goma Arda (HYDA)	156	2009	Goma Arda (HYDA)	156	2009	—	—	2009	—	—
2010	Combined Cycle	450	2010	Combined Cycle	450	2010	Combined Cycle	450	2010	Combined Cycle	450	2010	Sreden Iskar (HYDA)	44	2010	Sreden Iskar (HYD	44
	—	—		—	—		—	—		—	—		Goma Arda (HYDA)	156		—	—
	TOTAL	5125			4225			4225			4225			3775			3619

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Annex 5
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TABLE - 5.24 OPTIMUM SOLUTION - MEDIUM
ANNUAL ADDITIONS (MW)

SCENERIO 0

YEAR	PLANT NAME	CAP. (MW)
1993	—	—
1994	—	—
1995	Maritsa	300
	Devnia	160
	Republica	35
	Tsaicho Kostov	280
1996	Maritsa	150
	Burgas	500
	Tsaicho Kostov	140
1997	Combined Cycle	450
	Maritsa	160
	Republica	70
1998	Burgas	500
	Sreden Iskar (HYDA)	44
	—	—
	—	—
1999	Combined Cycle	450
	Varna	210
	Devnia	480
2000	Gorna Arda (HYDA)	156
	—	—
	—	—
2001	Varna	210
	—	—
	—	—
2002	Varna	210
2003	—	—
2004	Bobov Dol	200
2005	Bobov Dol	200
	—	—
2006	Bobov Dol	200
2007	—	—
2008	—	—
2009	Sredha Vacha (HYDB	120
	Nikopol	400
2010	Imported Coal	1000
	—	—
	—	—
TOTAL		6615

SCENERIO 1

YEAR	PLANT NAME	CAP. (MW)
1993	—	—
1994	—	—
1995	Maritsa	300
	Republica	35
	—	—
	—	—
1996	Maritsa	150
	Burgas	500
	—	—
1997	Combined Cycle	450
	Maritsa	150
	Republica	70
1998	Burgas	500
	Sreden Iskar (HYDA)	44
	—	—
	—	—
1999	Varna	210
	Devnia	640
	—	—
2000	Gorna Arda (HYDA)	156
	—	—
	—	—
2001	Varna	210
	—	—
	—	—
2002	Varna	210
2003	—	—
2004	Bobov Dol	200
2005	Bobov Dol	200
	—	—
2006	Bobov Dol	200
2007	—	—
2008	—	—
2009	Combined Cycle	450
	—	—
2010	Combined Cycle	450
	Tsaicho Kostov	140
	Sredha Vacha (HYDB	120
TOTAL		5385

SCENERIO 2

YEAR	PLANT NAME	CAP. (MW)
1993	—	—
1994	—	—
1995	Maritsa	150
	—	—
	—	—
	—	—
1996	Burgas	500
	Republica	35
	—	—
1997	Maritsa	150
	—	—
	—	—
1998	Maritsa	150
	Combined Cycle	450
	Burgas	500
	Sreden Iskar (HYDA)	44
1999	Maritsa	150
	Varna	210
	—	—
2000	Devnia	320
	Tsaicho Kostov	280
	Gorna Arda (HYDA)	156
2001	Varna	210
	Devnia	160
	Republica	35
2002	Varna	210
2003	Republica	35
2004	Bobov Dol	200
2005	Bobov Dol	200
	—	—
2006	Bobov Dol	200
2007	—	—
2008	—	—
2009	Combined Cycle	450
	—	—
2010	Combined Cycle	450
	Sredha Vacha (HYDB	120
	—	—
TOTAL		5365

SCENERIO 3

YEAR	PLANT NAME	CAP. (MW)
1993	—	—
1994	—	—
1995	Maritsa	150
	—	—
	—	—
	—	—
1996	—	—
	—	—
	—	—
1997	Maritsa	300
	Republica	105
	—	—
1998	Maritsa	150
	Burgas	1000
	Devnia	160
	Sreden Iskar (HYDA)	44
1999	Varna	210
	Devnia	480
	—	—
2000	Combined Cycle	450
	Gorna Arda (HYDA)	156
	—	—
2001	Varna	210
	—	—
	—	—
2002	Varna	210
2003	—	—
2004	Bobov Dol	200
2005	Bobov Dol	200
	—	—
2006	Bobov Dol	200
2007	—	—
2008	—	—
2009	Combined Cycle	450
	—	—
2010	Combined Cycle	450
	Tsaicho Kostov	140
	Sredha Vacha (HYD	120
TOTAL		5385

SCENERIO 4

YEAR	PLANT NAME	CAP. (MW)
1993	—	—
1994	—	—
1995	Maritsa	150
	—	—
	—	—
	—	—
1996	—	—
	—	—
	—	—
1997	Maritsa	300
	Republica	105
	—	—
1998	Maritsa	150
	Burgas	500
	Sreden Iskar (HYDA)	44
	—	—
1999	Varna	210
	Devnia	640
	—	—
2000	Gorna Arda (HYDA)	156
	—	—
	—	—
2001	Varna	210
	—	—
	—	—
2002	Varna	210
2003	—	—
2004	Bobov Dol	200
2005	Bobov Dol	200
	—	—
2006	Bobov Dol	200
2007	—	—
2008	—	—
2009	Combined Cycle	450
	—	—
2010	Combined Cycle	450
	—	—
	—	—
TOTAL		4175

SCENERIO 5

YEAR	PLANT NAME	CAP. (MW)
1993	—	—
1994	—	—
1995	Maritsa	150
	—	—
	—	—
	—	—
1996	—	—
	—	—
	—	—
1997	Maritsa	300
	Republica	105
	—	—
1998	Maritsa	300
	Burgas	1000
	—	—
	—	—
1999	Varna	210
	Devnia	640
2000	—	—
	—	—
	—	—
2001	Varna	210
	—	—
	—	—
2002	Varna	210
2003	—	—
2004	Bobov Dol	200
2005	Bobov Dol	200
	Sreden Iskar (HYDA)	44
2006	Bobov Dol	200
2007	—	—
2008	Gorna Arda (HYDA)	156
2009	Combined Cycle	450
	—	—
2010	Combined Cycle	450
	—	—
	—	—
TOTAL		4825

TABLE – 5.25 OPTIMUM SOLUTION – MAXIMUM ANNUAL ADDITIONS (MW)

YEAR	SCENERIO 0 PLANT NAME	CAP. (MW)	YEAR	SCENERIO 1 PLANT NAME	CAP. (MW)	YEAR	SCENERIO 2 PLANT NAME	CAP. (MW)	YEAR	SCENERIO 3 PLANT NAME	CAP. (MW)	YEAR	SCENERIO 4 PLANT NAME	CAP. (MW)	YEAR	SCENERIO 5 PLANT NAME	CAP. (MW)
1993	—	—	1993	—	—	1993	—	—	1993	—	—	1993	—	—	1993	—	—
1994	—	—	1994	—	—	1994	—	—	1994	—	—	1994	—	—	1994	—	—
1995	Maritsa	300	1995	Maritsa	300	1995	Maritsa	300	1995	Maritsa	150	1995	Maritsa	150	1995	Maritsa	150
	Devnia	160		Republica	35		Republica	35		—	—		—	—		—	—
	Republica	35		—	—		—	—		—	—		—	—		—	—
	Tsaicho Kostov	140		—	—		—	—		—	—		—	—		—	—
1996	Maritsa	300	1996	Maritsa	300	1996	Maritsa	300	1996	Maritsa	300	1996	Maritsa	150	1996	Maritsa	150
	Burgas	500		Burgas	500		Burgas	500		Burgas	500		—	—		—	—
	Devnia	320		Republica	70		Republica	70		Republica	35		—	—		—	—
	Republica	70		—	—		—	—		—	—		—	—		—	—
	Tsaicho Kostov	280		—	—		—	—		—	—		—	—		—	—
1997	Combined Cycle	1350	1997	Combined Cycle	450	1997	—	—	1997	Maritsa	150	1997	Maritsa	300	1997	Maritsa	300
	—	—		—	—		—	—		Republica	70		Republica	105		Republica	105
1998	Burgas	[illegible]	1998	Combined Cycle	900	1998	Combined Cycle	1350	1998	Combined Cycle	1350	1998	Burgas	1000	1998	Burgas	1000
	Sredan Iskar (HYDA)	44		Burgas	500		Burgas	600		Burgas	500		Sredan Iskar (HYDA)	44		—	—
1999	Varna	210	1999	Varna	210	1999	Varna	210	1999	Varna	210	1999	Varna	210	1999	Varna	210
	Devnia	160		Devnia	640		Devnia	640		Devnia	640		Devnia	640		Devnia	640
	—	—		Sredan Iskar (HYDA)	44		Sredan Iskar (HYDA)	44		Sredan Iskar (HYDA)	44		—	—		—	—
2000	Gorna Arda (HYDA)	156	2000	Gorna Arda (HYDA)	156	2000	Gorna Arda (HYDA)	156	2000	Gorna Arda (HYDA)	156	2000	Gorna Arda (HYDA)	156	2000	Sredan Iskar (HYDA)	44
	Sredna Vacha (HYDB	120		—	—		—	—		—	—		—	—		—	—
2001	Varna	210	2001	Varna	210	2001	Varna	210	2001	Varna	210	2001	Varna	210	2001	Varna	210
2002	Varna	210	2002	Varna	210	2002	Varna	210	2002	Varna	210	2002	Varna	210	2002	Varna	210
2003	Nikopol	400	2003	—	—	2003	—	—	2003	—	—	2003	—	—	2003	—	—
2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200	2004	Bobov Dol	200
	—	—		—	—		—	—		—	—		Combined Cycle	450		—	—
2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200	2005	Bobov Dol	200
	Tsaicho Kostov	140		—	—		—	—		—	—		—	—		—	—
2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200	2006	Bobov Dol	200
	—	—		—	—		—	—		—	—		Combined Cycle	450		Combined Cycle	450
2007	—	—	2007	—	—	2007	—	—	2007	—	—	2007	—	—	2007	—	—
2008	Tsaicho Kostov	140	2008	—	—	2008	—	—	2008	—	—	2008	—	—	2008	—	—
2009	Imported Coal	500	2009	Tsaicho Kostov	140	2009	Tsaicho Kostov	140	2009	Tsaicho Kostov	140	2009	Combined Cycle	450	2009	Combined Cycle	450
	—	—		Sredna Vacha (HYDB	120		Sredna Vacha (HYDB	120		Sredna Vacha (HYD	120		—	—		—	—
2010	Imported Coal	500	2010	Tsaicho Kostov	140	2010	Tsaicho Kostov	420	2010	Tsaicho Kostov	420	2010	Combined Cycle	450	2010	Combined Cycle	450
	Tsaicho Kostov	140		Nikopol	400		—	—		Nikopol	400		Tsaicho Kostov	140		—	—
	—	—		—	—		—	—		—	—		Sredna Vacha (HYD	120		—	—
	TOTAL	7485			5925			5905			6205			5836			4969

TABLE - 5.26 ENERGY OUTPUT BY PLANT (GWh) FOR MINIMUM FORECAST AND SCENARIO 1

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA21	888.77	898.78	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	869.44	876.71	787.66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	896.31	902.41	846.19	840.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	890.22	890.55	817.81	812.91	843.61	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1462.63	1468.98	1419.26	1417.26	1417.91	1453.12	1443.02	1468.62	1452.56	1404.35	1415.62	1433.19	1436.86	1443.23	1449.13	1447.37	1470.73	1470.43
MA26	1469.29	1469.39	1451.66	1456.44	1456.17	1469.51	1468.42	1472.63	1469.15	1442.53	1448.36	1460.83	1460.3	1463.17	1466.2	1465.57	1470.86	1469.43
MA27	1469.4	1469.4	1469.02	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1439.41	1439.41	1439.41	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1439.41	1439.41	1439.41	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1394.43	1394.43	1394.43	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.48	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1454.4	1454.4	1454.41	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	1026.64	958.02	544.77	667.96	761.11	997.25	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	1203.88	1188.97	891.09	1061.57	1136.68	1231.48	1210.21	0	0	0	0	0	0	0	0	0	0	0
VAR3	1269.21	1273.61	1106.56	1176.09	1224.89	1302.74	1286.94	0	0	0	0	0	0	0	0	0	0	0
VAR4	1197.05	1159.98	921.97	1006.18	1094.25	1214	1186.19	1335.57	1309.69	1244.65	1260.29	1216.26	1155.03	1067.36	1069.78	1110.94	0	0
VAR5	1163.98	1108.91	801.7	867.18	992.79	1159.14	1118.38	1311.99	1259.1	1196.98	1220.42	1152	1086.56	974.78	1008.24	1000.26	1230.56	0
VAR6	957.16	843.15	343.19	428.05	611.59	869.28	954.94	1262.04	1169	1099.54	1133.93	1087.53	924.18	776.79	830.49	842.01	1132.12	0
BOS1	604.16	342.46	31.47	125.13	160.27	479.53	653.52	995.71	898.42	760.42	812.62	0	0	0	0	0	0	0
BOS2	298.51	109.71	0.96	8.06	6.4	147.74	288.09	761.91	604.52	449.43	515.86	536.91	0	0	0	0	0	0
BOS3	468.5	200.5	1.49	23.07	67.94	275.24	461.42	861.09	739.1	629.96	674.32	679.41	0	0	0	0	0	0
KOZ1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03
KOZ6	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03
DHLI	736.61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	237.28	156.64	163.45	205.61	238.19	223.24	288.27	271.1	254.49	258.64	234.34	228.36	178.97	194.86	195.14	289.09	298.36
DHNG	1.58	8.81	8.96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	3.28	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOO	29.78	0.41	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	0.14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	189.49	137.98	23.06	51.74	75.33	178.03	208.28	0	0	0	0	0	0	0	0	0	0	[illegible]
INLI	151.9	151.82	151.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	214.99	17.36	0.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOO	582.34	598.21	166.97	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	203.81	191.94	40.31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	53.23	1.78	1.21	5.28	4.68	4.97	3.55	5.71	5.11	5.44	5.36	5.16	5.16	4.89	4.48	4.79	5.49	32.53
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3146.93
MARR	0	0	2167.25	3269.09	4384.92	4384.47	4384.99	4383.07	4385.51	4380.99	4383.68	4386.73	4387.06	4386.03	4385.75	4386.52	4382.92	4382.92
BOSR	0	0	0	0	0	0	0	0	0	0	0	1369.91	2706.2	3984.98	4038.64	4084.21	4254.76	4350.04
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.95	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	0	0	50.75	182.19	1294.33	775.29	433.64	553.48	535.31	1362.79	812.06	979.92	[illegible]	2613.79	3062.2
DEVI	0	0	0	0	0	0	7.35	20.87	7.49	7.97	7.38	7.09	27.82	7.18	8.91	14.7	267.74	509.84
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	60.76	224.34	438.62	496.16	670.32	621.71	532.78	569.63	502.1	444.71	333.41	363.91	420.31	587.06	672.04
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	36212.91	34329.29	33668.34	34350.72	35550.47	36751.08	37946.92	38658.82	39042.16	39424.98	39609.86	40209.79	40765.86	40992.7	41389.99	41778.82	42277.93	42546.09

TABLE – 6.27 ENERGY OUTPUT BY PLANT (GWh) FOR MINIMUM FORECAST AND SCENARIO 3

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	2684.78	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA21	579.39	461.89	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	450.19	290.43	160.17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	626.76	612.17	339.74	403.18	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	513.46	390.6	244.9	296.46	402.73	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1092.2	937.7	703.03	777.61	796.4	1453.12	1443.92	1469.62	1452.56	1404.36	1415.62	1433.19	1436.86	1443.23	1449.13	1447.37	1470.73	1470.43
MA26	1175.64	1101.64	876.04	963.31	993.7	1469.51	1468.42	1472.63	1469.15	1442.53	1448.36	1460.83	1460.8	1463.17	1466.2	1465.67	1470.66	1469.43
MA27	1246.99	1206.36	1046.72	1159.26	1263.27	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1321.34	1386.26	1407.53	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1277.29	1256.66	1147.09	1257.61	1311.62	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1324.3	1316.79	1227.63	1323.13	1351.51	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1345.39	1353.12	1339.87	1364.21	1379.45	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1375.93	1378.41	1360.01	1398.66	1418.95	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	30.52	0.95	0.59	3.34	2.5	997.25	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	426.61	136.64	48.62	145.73	211.65	1231.46	1210.21	0	0	0	0	0	0	0	0	0	0	0
VAR3	661.2	232.27	146.16	263.77	397.56	1302.74	1296.94	0	0	0	0	0	0	0	0	0	0	0
VAR4	291.86	45.2	3.71	39.01	130.11	1214	1186.19	1336.57	1309.69	1244.65	1260.29	1210.25	1155.03	1087.35	1099.76	1110.24	0	0
VAR5	162.16	2.86	1.2	3.16	29.62	1159.14	1116.38	1311.99	1259.1	1198.96	1220.62	1152	1085.58	974.73	1006.24	1000.26	1230.56	0
VAR6	3.01	0.61	0.48	3.21	3.06	869.28	954.94	1252.04	1169	1099.54	1133.93	1037.53	924.16	776.79	830.49	842.01	1132.12	0
BOB1	0.42	0.61	0.54	2.38	2.53	479.53	653.52	995.71	898.42	760.42	812.62	0	0	0	0	0	0	0
BOB2	0.07	0.34	0.46	2.28	2.06	147.74	268.09	751.91	604.52	449.43	515.66	535.91	0	0	0	0	0	0
BOB3	0.16	0.51	0.39	2.24	2.15	275.24	461.42	651.06	739.1	629.86	674.32	679.41	0	0	0	0	0	0
KOZ1	3005.11	3005.11	3005.11	3005.11	3005.11	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	2245.92	2245.92	2245.92	2245.92	2245.92	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ4	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03
KOZ6	4826.35	4847.46	4831.4	4863.32	4873.14	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03
DHLI	54.67	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	0.31	0.17	0.66	0.67	236.19	223.24	268.27	271.1	254.49	266.64	234.34	226.36	176.97	194.65	195.14	269.09	296.36
DHNG	0.03	0.71	0.72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	1.76	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHC.I	0.02	0.16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	0.11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	0.19	0.14	0.21	0.7	0.71	173.03	203.26	0	0	0	0	0	0	0	0	0	0	0
INLI	147.21	146.36	146.65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	0.09	0.6	0.91	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	0.85	0.32	0.58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	0.25	0.16	0.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	0.06	0.83	0.99	6.05	4.71	4.97	3.56	5.71	6.11	5.44	5.36	5.16	5.16	4.89	4.48	4.79	5.49	32.56
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3145.93
MARR	0	0	0	0	676.26	4384.47	4384.99	4383.07	4385.61	4360.99	4383.66	4366.73	4367.06	4366.03	4365.75	4366.62	4362.92	4362.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1369.91	2706.2	3964.96	4036.64	4084.21	4254.76	4350.04
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.96	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRYB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	0	0	50.75	162.19	1234.33	775.29	433.64	553.46	635.31	1362.79	812.06	979.92	1267.76	2613.79	3062.2
DEVI	0	0	0	0	0	0	7.36	20.67	7.49	7.97	7.36	7.09	27.82	7.16	8.91	14.7	267.74	509.64
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	0	1.11	436.82	496.16	670.32	621.71	632.76	569.63	602.1	444.71	333.41	363.91	420.31	567.06	672.04
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	36213.64	34332.44	33861.63	34366.46	35605.14	36751.06	37946.92	38658.82	39042.16	39424.96	39609.66	40209.79	40765.86	40992.7	41369.99	41779.82	42277.93	42646.09

TABLE - 5.28 ENERGY OUTPUT BY PLANT (GWh) FOR MINIMUM FORECAST AND SCENARIO 4

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	9157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA21	579.39	461.69	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	450.19	290.43	180.17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	626.76	512.17	339.74	403.18	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	513.48	390.6	244.9	298.46	402.76	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1092.2	937.7	703.03	777.61	795.4	1224	1165.01	1210.54	1110.78	1042.69	1081.04	1118.34	1138.64	1175.34	1196.43	1217.63	1311.76	1374.86
MA26	1175.64	1101.64	676.04	963.31	993.7	1308.77	1273.63	1305.46	1227.93	1174.1	1195.95	1220.91	1242.71	1257.69	1275.16	1295.63	1365.62	1421.72
MA27	1245.99	1206.36	1046.72	1159.26	1263.27	1469.13	1468.43	1470.13	1470.64	1468.9	1469.63	1470.09	1470.35	1470.31	1470.13	1469.5	1469.43	1469.43
MA28	0	0	1321.34	1365.26	1407.53	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1277.26	1265.56	1147.09	1257.81	1311.62	1439.72	1440.45	1439.86	1439.84	1440.29	1440.03	1439.82	1439.46	1439.47	1439.44	1439.44	0	0
MA32	1324.3	1316.79	1227.63	1323.13	1351.51	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1345.39	1363.12	1339.67	1384.21	1379.45	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1375.93	1378.41	1380.01	1396.66	1416.95	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	30.52	0.95	0.59	3.34	2.5	331.6	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	425.81	136.54	48.62	145.73	211.66	849.63	801.41	0	0	0	0	0	0	0	0	0	0	0
VAR3	561.2	232.27	148.18	253.77	367.56	1016.46	958.16	0	0	0	0	0	0	0	0	0	0	0
VAR4	291.86	46.2	3.71	39.01	130.11	601.7	719.06	1010.79	926.58	791.65	840.37	729.27	687.82	521.47	563.52	602.55	0	0
VAR5	162.16	2.86	1.2	3.18	23.82	570.05	669.79	898.8	816.57	662.44	690.63	610.3	567.4	358.51	411.77	471.33	781.06	0
VAR6	3.91	0.51	0.48	3.21	3.05	194.93	340.66	735.52	707.72	522.17	569.23	432.77	333.86	185.99	241.36	315.1	636.32	0
BOB1	0.42	0.61	0.54	2.38	2.53	3.14	57.68	504.9	349.9	258.33	307.37	0	0	0	0	0	0	0
BOB2	0.07	0.34	0.46	2.26	2.06	1.61	1.86	181.39	80.12	7.08	20.04	30.45	0	0	0	0	0	0
BOB3	0.18	0.61	0.39	2.24	2.16	1.9	2.27	302.29	170.31	84.36	135.89	158.75	0	0	0	0	0	0
KOZ1	3005.11	3005.11	3005.11	3005.11	3005.11	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	2245.92	2245.92	2245.92	2245.92	2245.92	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05
KOZ4	3068.37	3068.37	3068.37	3068.37	3068.37	3068.55	3068.55	3068.55	3068.56	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.56	3068.55	3068.55
KOZ5	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.04
KOZ6	4820.35	4847.46	4831.4	4863.32	4873.14	4876.03	4876.03	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.04
DHLI	64.67	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	0.31	0.17	0.66	0.67	100.62	100.63	179.66	149	125.01	132.09	112.04	92.63	69.02	73.6	65.31	170.44	204.69
DHNG	0.93	0.71	0.72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	1.78	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	0.02	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOP	0	0	0.11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	0.19	0.14	0.21	0.7	0.71	3.3	49.76	0	0	0	0	0	0	0	0	0	0	0
INLI	147.21	148.36	146.65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	0.09	0.6	0.91	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	0.86	0.32	0.58	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	0.25	0.16	0.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	0.05	0.83	0.99	8.05	4.71	5.2	4.62	5.14	4.97	4.79	4.28	3.96	3.67	3.43	3.04	4.11	4.56	5.36
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MARR	0	0	0	0	876.26	4237.62	4099.54	4190.17	4063.1	3925.38	3969.1	4021.99	4053.09	4096.86	4134.3	4165.72	4280.81	4365.37
BOBR	0	0	0	0	0	0	0	0	0	0	0	967.13	1867.99	2684.42	2786.66	2842.86	3445.03	3663.96
VARR	0	0	0	0	0	0	1487.35	1507.59	2934	4396.65	4411.17	4423.73	4429.05	4440.6	4447.29	4453.57	4458.93	4457
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	0	0	11.16	9.94	56.96	13.59	12.26	11.79	11.59	76.36	13.78	22.34	49.59	755.4	2276.96
DEVI	0	0	0	0	0	0	5.95	7.16	6.45	6.75	6.31	6	6.7	5.78	5.42	6.77	7.65	225.77
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	0	1.11	31.09	128.22	386.91	326.75	239.63	261.74	188.74	103.26	25.48	52.34	95.94	326.51	539.96
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	36213.64	34332.44	33681.63	34365.48	35565.14	36759.5	37954.08	38666.89	39049.62	39432.23	39816.21	40215.5	40791.47	40997.9	41394.57	41784.79	42262.07	42546.24

TABLE - 5.29 ENERGY OUTPUT BY PLANT (GWh) FOR MEDIUM FORECAST AND SCENARIO 1

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235.6
MA21	900.47	904.24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	891.34	903.45	902.96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	902.61	904.24	904.16	904.27	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	896.97	904.23	903.4	904.3	904.27	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1468.99	1469.4	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1470.82	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA26	1469.4	1469.4	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA27	1469.4	1469.4	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1439.41	1439.41	1439.41	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1439.41	1439.41	1439.41	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1394.43	1394.43	1394.43	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.48	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1454.4	1454.4	1454.41	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	1154.36	1252.53	1212.28	1299.33	1316.22	1351.3	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	1260.59	1311.01	1299.59	1323.59	1324.58	1322.14	1324.14	0	0	0	0	0	0	0	0	0	0	0
VAR3	1314.09	1347.31	1342.7	1352.85	1351.46	1350.33	1351.24	0	0	0	0	0	0	0	0	0	0	0
VAR4	1269.79	1334.85	1315.71	1355.65	1361.96	1368.1	1362.8	1364.65	1366.83	1365.7	1365.04	1367.31	1368.08	1366.49	1367.57	1366.73	0	0
VAR5	1254.99	1326.02	1299.8	1360.53	1370.38	1390.49	1377.29	1395.38	1394.07	1396.48	1397.9	1395.67	1389.96	1386.78	1390.94	1388.08	1394.1	0
VAR6	1121.85	1226.68	1177.52	1285.91	1313.56	1369.5	1375.06	1426.35	1420.16	1417.61	1420.71	1411.51	1396.54	1381.12	1393.43	1393.35	1424.9	0
BOB1	814.62	924.61	836.97	1056.2	765.04	935	1004.11	1172.84	1131.86	1115.46	1137.69	0	0	0	0	0	0	0
BOB2	624.27	712.25	613.87	842.22	499.92	756.61	822.71	1073.72	1004.4	963.35	1007.21	1035.19	0	0	0	0	0	0
BOB3	684.9	779.21	711.28	939.52	625.39	814.72	868.96	1094.02	1040.29	1017.33	1050.86	1072.68	0	0	0	0	0	0
KOZ1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5	4876.03	4876.03	4876.04	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03
KOZ6	4876.03	4876.03	4876.04	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.04	4876.03
DHLI	806.13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	269.65	276.39	294.94	296.62	305.61	303.32	309.14	309.02	306.81	309.32	307.76	305.7	303.68	305.42	304.78	306.75	306.35
DHNG	66.14	40.13	17.97	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	59.66	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	103.27	103.23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	57.84	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	252.33	263.85	257.87	311.06	246.09	262.13	308	0	0	0	0	0	0	0	0	0	0	0
INLI	151.9	151.82	151.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	707.63	753.43	567.42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	740.26	614.96	779.66	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	273.15	320.06	299.42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	354.12	365.35	299.65	442.5	92.45	31.47	5.4	45.07	11.58	6.45	9.24	18.32	159.96	73.11	144.19	223.97	253.58	399.16
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COPL	0	0	0	0	2950.96	3102.36	3179.12	3365.96	3314.41	3294.29	3327.8	3273.25	3192.42	3113.23	3169.76	3214.44	6563.99	10096.36
MARR	0	0	2191.46	3287.19	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1460.99	2924.02	4386.16	4384.68	4385.5	4382.92	4382.92
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.95	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	1425.46	474.7	1343.62	1939.26	3236.35	2842.79	2175.27	2490.85	2762.07	3701	3223.33	3570.62	3831.56	3878.54	4176.36
DEVI	0	0	0	0	0	0	127.6	537.99	398.07	261.32	348.84	421.16	744.53	645.88	675.2	837.94	955.75	1329.96
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	201.25	233.62	590	660.24	691.1	756.04	728.87	723.96	736.56	720.17	690.92	669.59	687.5	703.27	692.75	717.53
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	62.74
TOTAL	38876.41	39308.34	41416.43	42481.42	43689.21	44796.89	45978.69	46207.51	46633.27	47392.24	47956.96	48600.15	49226.96	49803.36	50443.34	51003.63	51769.86	52186.13

TABLE - 5.30 ENERGY OUTPUT BY PLANT (GWh) FOR MEDIUM FORECAST AND SCENARIO 3

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235.6
MA21	692.47	746.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	618.98	673.47	687.98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	722.63	773.46	755.34	833.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	658.92	715.68	725.36	804.18	799.98	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1222.78	1298.58	1270.55	1380.28	1345.12	1469.43	1469.43	1469.43	1470.82	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA26	1283.78	1355.5	1334.08	1411.22	1391.87	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA27	1394.57	1400.46	1411.25	1445.7	1457.28	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1463.59	1470.34	1469.55	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1347.08	1401.86	1409.37	1431.04	1438.95	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.48	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1377.95	1421.08	1425.78	1438.73	1440.28	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.48	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1372.32	1391.87	1393.88	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1415.47	1446.75	1452.39	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.48	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	204.68	236	271.42	451.35	446.02	1358.14	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	667.04	676.08	727.76	963.65	969.27	1321.6	1322.81	0	0	0	0	0	0	0	0	0	0	0
VAR3	825.41	846.92	906.03	1118.74	1115.63	1350.33	1350.33	0	0	0	0	0	0	0	0	0	0	0
VAR4	577.51	588.35	613.13	868.59	853.88	1368.03	1366.66	1364.85	1366.63	1365.7	1365.04	1367.31	1368.06	1366.49	1367.57	1366.73	0	0
VAR5	456.77	403.04	450.8	710.52	700.01	1393.48	1385.36	1395.38	1394.07	1398.48	1397.9	1395.67	1389.96	1386.78	[illegible]	1388.08	1394.1	0
VAR6	123.76	116.95	197.43	297.98	277.19	1371.89	1385.1	1426.35	1420.16	1417.81	1420.71	1411.51	1398.54	1381.12	1393.43	1393.35	1424.9	0
BOB1	3.2	1.23	2.88	131.06	80.07	1156.19	1164.9	1172.84	1131.86	1115.46	1137.59	0	0	0	0	0	0	0
BOB2	0.78	0.87	0.8	4.13	3.2	1030.26	1094.26	1073.72	1004.4	963.36	1007.21	1036.19	0	0	0	0	0	0
BOB3	1.39	0.86	1.08	36.73	7.94	1069.61	1109.95	1094.02	1040.29	1017.33	1060.86	1072.58	0	0	0	0	0	0
KOZ1	3005.11	3005.11	3005.11	3005.11	3005.11	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	2245.92	2245.92	2245.92	2245.92	2245.92	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ4	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5	4876.03	4876.03	4876.03	4876.03	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03
KOZ6	4857.78	4875.54	4876.03	4876.03	4876.04	4876.04	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.04	4876.03
DHLI	220.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	58.61	87.04	129.45	133.95	304.48	301.98	309.14	309.02	306.81	309.32	307.76	305.7	303.66	305.42	304.76	306.75	306.35
DHNG	0.06	0.57	0.74	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	1.46	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	0.06	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	2.77	0.49	2.79	46.43	33.73	335.68	341.36	0	0	0	0	0	0	0	0	0	0	0
INLI	149.92	151.67	151.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	0.36	0.77	1.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	33.47	16.93	53.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	5.43	1.43	7.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	0.15	0.9	1.13	5.72	5.06	273.41	94.56	45.07	11.58	8.45	9.24	18.32	169.98	73.11	144.19	223.97	253.58	399.16
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	0	0	0	3385.96	3314.41	3294.29	3327.8	3273.25	3192.42	3113.23	3169.78	3214.44	6583.99	10096.36
MARR	0	0	1029.53	1070.88	3201.22	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1460.99	2924.02	4386.16	4384.68	4385.6	4382.92	4382.92
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.86	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	0	0	3093.35	3843.52	3238.35	2842.79	2175.27	2490.85	2762.07	3701	3223.33	3570.62	3631.58	3878.54	4176.38
DEVI	0	0	0	0	0	175.99	683.97	537.99	398.07	261.32	348.84	421.16	744.53	545.88	675.2	837.94	955.75	1329.98
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	0	94.26	757.46	768.61	755.04	729.87	723.95	736.56	720.17	690.92	669.59	687.5	703.27	692.75	717.53
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	62.74
TOTAL	38885.64	39312.38	41419.62	42509.3	43696.33	44785.48	45972.07	46207.51	46833.27	47392.24	47965.96	48600.15	49226.98	49803.36	50443.34	51003.63	51769.86	52186.13

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TABLE - 5.31 ENERGY OUTPUT BY PLANT (GWh) FOR MEDIUM FORECAST AND SCENARIO 4

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA21	692.47	746.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	618.96	673.47	667.96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	722.63	773.46	755.34	833.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	658.92	715.86	725.36	804.18	799.96	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1222.78	1296.56	1270.55	1380.26	1345.12	1470.21	1444.35	1464.41	1424.69	1420.44	1432.96	1442.26	1453.84	1459.96	1463.38	1469.97	1464.7	1470.28
MA26	1263.78	1356.5	1334.06	1411.22	1391.87	1470.83	1461.63	1465.82	1446.89	1451.71	1458.96	1463.14	1469.31	1471.38	1471.8	1471.53	1468.86	1469.74
MA27	1334.57	1400.46	1411.25	1446.7	1457.28	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1463.59	1470.34	1469.56	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1347.08	1401.86	1409.37	1431.04	1436.95	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1377.95	1421.06	1425.76	1436.73	1440.28	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1372.32	1391.87	1393.86	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.48	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1415.47	1446.75	1452.39	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	204.66	236	271.42	451.36	446.02	1146.3	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	667.04	676.06	727.76	963.86	969.27	1284.46	1247.86	0	0	0	0	0	0	0	0	0	0	0
VAR3	825.41	846.92	905.03	1116.74	1116.63	1340.46	1302.9	0	0	0	0	0	0	0	0	0	0	0
VAR4	577.61	588.35	613.13	868.59	853.86	1261.97	1263.47	1331.96	1307.03	1274.31	1291.68	1263.96	1236.36	1202.91	1227.05	1249.59	0	0
VAR5	455.77	403.04	450.8	710.62	700.01	1248.05	1222.9	1328.67	1292.94	1243.1	1266.16	1232.75	1198.9	1154.44	1167.08	1222.62	1343.67	0
VAR6	123.76	118.95	197.43	297.98	277.19	1063.84	1132.29	1267.2	1236.46	1162.63	1212.18	1168.89	1119.96	1036.12	1097.07	1159.43	1319.68	0
BOB1	3.2	1.23	2.88	131.06	80.07	746.21	654.49	1061.31	997.92	916.34	970.6	0	0	0	0	0	0	0
BOB2	0.78	0.67	0.8	4.13	3.2	649.43	682.22	862.39	817.23	720.91	759.02	789.97	0	0	0	0	0	0
BOB3	1.39	0.88	1.06	38.73	7.94	646.74	756.32	944.62	891.79	778.16	826.26	673.6	0	0	0	0	0	0
KOZ1	3005.11	3005.11	3005.11	3005.11	3005.11	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	2245.92	2245.92	2245.92	2245.92	2245.92	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05
KOZ4	3068.37	3068.37	3068.37	3068.37	3068.37	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55
KOZ5	4876.03	4876.03	4876.03	4876.03	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03
KOZ6	4857.76	4876.54	4876.03	4876.03	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.04	4876.04	4876.03	4876.04	4876.03
DHLI	220.25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	58.61	67.04	129.46	133.96	262.99	252.63	265.25	270.31	267.93	271.86	265.24	258.63	232.15	246.2	262.25	265.89	304.18
DHNG	0.06	0.57	0.74	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	1.46	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	0.06	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	2.77	0.49	2.79	46.43	33.73	220.65	263.45	0	0	0	0	0	0	0	0	0	0	0
INLI	149.92	151.67	151.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	0.38	0.77	1.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	33.47	16.93	53.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	5.43	1.43	7.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	0.16	0.9	1.13	5.72	5.06	6.59	4.43	7.39	6.22	5.38	5.36	5.56	20.25	6.96	15.06	43.52	61.61	243.96
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2699.47	6357.63
MARR	0	0	1029.63	1070.88	3201.22	4363.06	4384.96	4384.49	4374.1	4366.97	4366.07	4367.91	4367.36	4365.89	4365.34	4363.5	4364.05	4362.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1400.25	2785.48	4169.09	4213.09	4258.24	4298	4366.76
VARR	0	0	0	0	0	0	1513.22	1513.22	2971.74	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	0	0	683.95	1184.04	2424.3	2099.26	1710.27	1959.17	2165.14	2926.11	2504.04	2617.63	3006.21	3169.55	3600.32
DEVI	0	0	0	0	0	0	14.63	262.66	152.27	59.95	121.61	180.78	445.29	306.22	417.1	535.15	569.95	883.46
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	0	94.26	555.41	596.11	699.23	657.75	630.67	649.72	616.22	572.3	627.99	558.79	600.47	604.45	641.51
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	38885.64	39312.36	41419.62	42509.3	43696.33	44801.29	45960.22	46211.21	46836.22	47394.9	47958.33	48602.61	49230.4	49606.99	50446.38	51009.31	51777.48	52188.73

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TABLE - 5.32 ENERGY OUTPUT BY PLANT (GWh) FOR MAXIMUM FORECAST AND SCENARIO 1

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.76	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235.6	2137.62
MA21	900.47	904.24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	891.34	903.45	902.96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	902.61	904.24	904.16	904.27	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	898.97	904.23	903.4	904.27	904.27	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1468.99	1469.4	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA26	1469.4	1469.4	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA27	1469.4	1469.4	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1469.4	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1439.41	1439.41	1439.41	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1439.41	1439.41	1439.41	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1394.43	1394.43	1394.43	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.48	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1454.4	1454.4	1454.41	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	1154.38	1252.53	1212.26	1292.73	1347.38	1381.02	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	1260.59	1311.01	1289.59	1323.66	1322.69	1321.29	1321.29	0	0	0	0	0	0	0	0	0	0	0
VAR3	1314.09	1347.91	1342.7	1352.66	1350.33	1350.33	1350.33	0	0	0	0	0	0	0	0	0	0	0
VAR4	1269.79	1334.85	1315.71	1353.67	1368	1364.65	1364.65	1364.85	1364.85	1364.85	1364.65	1364.65	1364.85	1364.68	1364.63	1364.65	0	0
VAR5	1254.99	1328.02	1299.8	1356.63	1389.22	1395.9	1396.11	1393.89	1393.9	1393.89	1393.89	1393.89	1393.89	1395.92	1393.95	1393.89	1393.89	0
VAR6	1121.65	1226.68	1177.52	1276.62	1356.75	1409.44	1422.59	1422.96	1424.49	1423.63	1422.93	1423.67	1425.61	1425.99	1426.02	1424.93	1422.93	0
BOB1	814.62	924.61	836.97	1006.32	938.87	479.97	704.28	999.53	947.58	883.62	954.93	0	0	0	0	0	0	0
BOB2	624.27	712.25	613.87	775.79	678.05	183.03	344.81	636.46	798.49	703.56	770.89	812.16	0	0	0	0	0	0
BOB3	684.9	779.21	711.28	863.46	780.6	292.19	529.54	883.29	847.17	764.28	833.76	883.37	0	0	0	0	0	0
KOZ1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03
KOZ6	4876.03	4876.03	4876.04	4876.04	4876.04	4876.03	4876.04	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03
DHLI	808.13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLP	0	289.85	278.39	293.8	302.66	309.33	307.32	308.36	308.35	308.35	308.35	308.35	308.46	309.34	308.59	308.38	306.35	308.35
DHNG	66.14	40.13	17.97	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	22.39	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	103.27	103.23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	57.84	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	252.33	283.85	257.87	301.78	268.34	165.02	219.91	0	0	0	0	0	0	0	0	0	0	0
INLI	151.9	151.62	151.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	707.63	753.43	657.42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	740.25	814.96	779.68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	273.15	320.06	299.42	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	354.12	365.36	299.65	328.17	276.86	4.69	4.18	7.26	6.3	6.32	6.67	7	69.79	14.65	37.33	66.05	388.41	754.06
GTRL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	3113.01	8679.42	9272.19	9957.05	9614.58	9681.6	9646.64	9717.61	9627.72	9263.73	9515.38	9521.76	10071.86	10261.32
MARR	0	0	2191.46	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1460.99	2921.91	4382.92	4382.92	4382.92	4382.92	4382.92
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.95	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	1103.46	884.37	170.32	439.26	1769.65	1506.94	1284.18	1698.83	1995.13	2933.44	2473.58	2587.13	2827.94	4196.66	4830.37
DEVI	0	0	0	0	0	0	8.72	185.59	112.6	52.74	155.06	248.14	526.75	397.19	469.67	650.23	1214.42	2173.43
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	201.26	688.15	664.61	414.94	549.56	672.8	629.6	604.63	651.28	621.06	597.9	525.52	576.65	590.66	712.13	771.18
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57.46	486.12
TOTAL	38678.41	39306.34	41415.43	43331.84	45151.82	47107.54	49173.43	50212.46	51021.38	51825.76	52761.87	53590.41	54526.18	54907.73	55417.48	55785.82	56299.22	56580.49

TABLE - 5.33 ENERGY OUTPUT BY PLANT (GWh) FOR MAXIMUM FORECAST AND SCENARIO 3

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235.8	2137.62
MA21	692.47	746.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	618.98	673.47	687.98	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	722.63	773.46	755.34	777.48	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	658.92	715.86	725.36	739.1	797.98	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1222.78	1298.58	1270.55	1322.95	1347.74	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA26	1283.78	1355.5	1334.06	1378.07	1393.82	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA27	1334.57	1400.46	1411.26	1454.54	1468.37	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1463.59	1469.74	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1347.08	1401.86	1409.37	1435.92	1440.16	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1377.95	1421.08	1425.76	1440.29	1439.73	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1372.32	1391.87	1393.86	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1415.47	1446.75	1452.39	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	204.66	235	271.42	308.09	490.11	1381.02	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	667.04	678.08	727.76	836.03	1002.81	1321.29	1321.29	0	0	0	0	0	0	0	0	0	0	0
VAR3	825.41	846.92	905.03	1007.06	1133.05	1360.33	1360.33	0	0	0	0	0	0	0	0	0	0	0
VAR4	577.51	588.35	613.13	691.53	695.56	1364.85	1364.85	1364.85	1364.85	1364.85	1364.85	1364.85	1364.85	1364.88	1364.83	1364.85	0	0
VAR5	455.77	403.04	450.8	504.87	750.65	1395.9	1396.11	1393.89	1393.9	1393.89	1393.89	1393.89	1393.89	1395.92	1393.95	1393.89	1393.89	0
VAR6	123.76	116.95	197.43	167	347.95	1409.44	1422.59	1422.95	1424.49	1423.63	1422.93	1423.67	1425.61	1425.99	1425.02	1424.93	1422.93	0
BOB1	3.2	1.23	2.88	24.74	110.87	479.97	704.28	998.53	947.58	863.62	954.93	0	0	0	0	0	0	0
BOB2	0.78	0.87	0.8	2.96	3.97	163.03	344.81	836.46	796.49	703.56	770.89	812.16	0	0	0	0	0	0
BOB3	1.39	0.86	1.06	3.94	26.42	292.19	529.54	883.29	847.17	764.28	833.76	883.37	0	0	0	0	0	0
KOZ1	3005.11	3005.11	3005.11	3005.11	3005.11	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	2245.92	2245.92	2245.92	2245.92	2245.92	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ4	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ5	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03
KOZ6	4857.78	4875.54	4876.03	4876.04	4876.04	4876.03	4876.04	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03
DHLI	220.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLF	0	58.61	87.04	94.19	143.4	309.33	307.32	308.35	308.35	308.35	308.35	308.35	308.46	309.34	308.59	308.38	308.35	308.35
DHNG	0.06	0.57	0.74	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNP	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	0.06	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	2.77	0.49	2.79	20.03	46.24	165.02	219.91	0	0	0	0	0	0	0	0	0	0	0
INLI	149.32	151.67	151.8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	0.38	0.77	1.28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	33.47	16.93	53.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	5.43	1.43	7.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	0.15	0.9	1.13	6.66	4.75	4.89	4.18	7.25	6.3	6.32	6.57	7	69.79	14.65	37.33	65.05	368.41	764.05
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	0	8679.42	9272.19	9957.05	9814.56	9681.6	9646.54	9717.61	9627.72	9263.73	9515.38	9521.76	10071.86	10261.32
MARR	0	0	1029.53	3185.63	4292.42	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92	4382.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1460.99	2921.91	4382.92	4382.92	4382.92	4382.92	4382.92
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.95	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	4.86	5.67	170.32	439.28	1769.65	1506.94	1284.18	1698.83	1995.13	2933.44	2473.58	[illegible]	2827.94	4196.68	4830.37
DEVI	0	0	0	0	0	0	8.72	185.59	112.6	52.74	155.05	248.14	526.75	397.19	[illegible]	550.23	1214.42	2173.43
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	22.56	132.3	414.94	549.56	672.8	629.6	604.53	651.26	621.06	697.9	526.52	576.65	590.86	712.13	771.16
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57.48	488.12
TOTAL	38885.64	39312.36	41419.62	43354.13	45174.44	47107.54	49173.43	50212.46	51021.36	51625.76	52761.57	53690.41	54526.16	54907.73	55417.48	55785.82	58299.22	58690.49

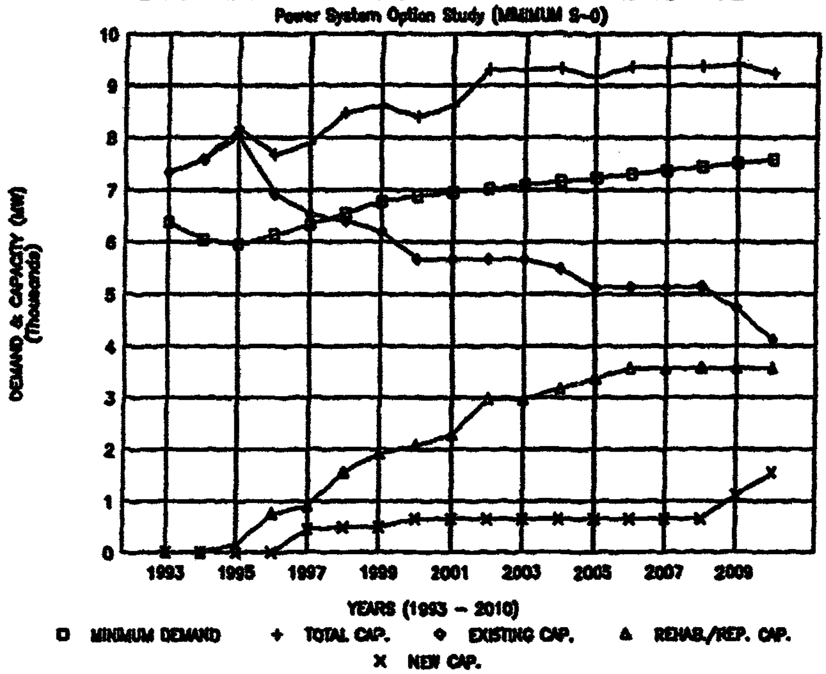
TABLE - 5.34 ENERGY OUTPUT BY PLANT (GWh) FOR MAXIMUM FORECAST AND SCENARIO 4

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
HYDA	2445.12	2445.12	2445.12	2445.12	2445.12	2684.78	2684.78	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1	3157.1
HYDB	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	235.6
MA21	692.47	748.19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA22	616.96	673.47	687.96	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA23	722.63	773.48	756.34	823.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MA24	658.92	715.66	726.36	797.73	806.16	0	0	0	0	0	0	0	0	0	0	0	0	0
MA25	1222.78	1296.56	1270.55	1372.68	1355.42	1470.5	1469.77	1470.55	1464.47	1473.61	1472.71	1467.48	1469.4	1469.32	1469.43	1469.46	1469.43	1469.43
MA26	1263.78	1355.5	1334.06	1407.09	1395.84	1469.44	1471.27	1470.69	1469.28	1471.25	1469.86	1469.99	1470.57	1470.49	1469.43	1469.43	1469.43	1469.43
MA27	1334.57	1400.46	1411.25	1454.54	1466.37	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA28	0	0	1463.59	1469.74	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.43	1469.45	1469.41	1469.43	1469.43	1469.43	1469.43	1469.43
MA31	1347.06	1401.86	1409.37	1435.92	1440.16	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	0	0
MA32	1377.95	1421.08	1425.76	1440.29	1439.73	1439.44	1439.44	1439.44	1439.44	1439.44	1439.44	1439.46	1439.42	1439.44	1439.44	1439.44	1439.44	0
MA33	1372.32	1391.87	1393.86	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.46	1394.48	1394.44	1394.46	1394.46	1394.46	1394.46	1394.46
MA34	1415.47	1446.75	1452.39	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.44	1454.46	1454.42	1454.44	1454.44	1454.44	1454.44	1454.44
VAR1	204.66	235	271.42	427.56	509.24	1251.47	0	0	0	0	0	0	0	0	0	0	0	0
VAR2	667.04	678.08	727.76	963.07	1005.09	1317.46	1298.09	0	0	0	0	0	0	0	0	0	0	0
VAR3	825.41	846.92	905.03	1106.64	1139.62	1351.54	1342.29	0	0	0	0	0	0	0	0	0	0	0
VAR4	577.51	588.35	613.13	831.82	897.6	1340.9	1320.08	1365.48	1356.46	1362.96	1367.31	1351.29	1346.09	1334.82	1354.08	1352.36	0	0
VAR5	455.77	403.04	450.8	667.1	768.11	1332.29	1320.42	1389.28	1373.04	1373.37	1385.08	1365.58	1359.72	1342.77	1384.89	1359.37	1389.38	0
VAR6	123.78	116.95	197.43	256.45	327.95	1224.45	1300.33	1393.17	1375.23	1358.38	1380.97	1363.75	1353.01	1328.64	1349.9	1341.46	1398.58	0
BOB1	3.2	1.23	2.88	116.67	109.64	984.02	1053.63	1208.74	1179.06	1154.97	1183.55	0	0	0	0	0	0	0
BOB2	0.78	0.87	0.8	3.84	3.83	740.78	802.45	1141.32	1074.23	1066.44	1109.38	943.61	0	0	0	0	0	0
BOB3	1.39	0.88	1.08	28.07	25.4	805.63	966.04	1145.07	1062.33	1079.81	1111.54	978.16	0	0	0	0	0	0
KOZ1	3005.11	3005.11	3005.11	3005.11	3005.11	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ2	3068.37	3068.37	3068.37	3068.37	3068.37	0	0	0	0	0	0	0	0	0	0	0	0	0
KOZ3	2245.92	2245.92	2245.92	2245.92	2245.92	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05	2246.05
KOZ4	3068.37	3068.37	3068.37	3068.37	3068.37	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55	3068.55
KOZ5	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.04	4876.03	4876.03	4876.03	4876.04	4876.03	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03
KOZ6	4857.78	4875.54	4876.03	4876.03	4876.04	4876.04	4876.03	4876.03	4876.04	4876.04	4876.04	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03	4876.03
DHLI	220.25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHLF	0	58.61	87.04	129.67	132.54	284.94	283.61	304.42	289.1	298.94	302.98	297.37	296.4	291.01	297.68	294.99	305.9	308.62
DHNG	0.06	0.57	0.74	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHNF	0	0	0	1.49	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCO	0.06	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHCP	0	0	0.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DHOI	2.77	0.49	2.79	41.9	41.03	287.78	311.64	0	0	0	0	0	0	0	0	0	0	0
INLI	149.92	161.67	151.6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INNG	0.36	0.77	1.26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INCO	33.47	16.93	53.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
INOI	5.43	1.43	7.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPR	0.15	0.9	1.13	5.8	6.09	86.06	11.72	330.17	259.77	178.8	301.15	36.79	245.68	123.15	166.63	237.97	234.16	306.11
GTPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IMPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CCPL	0	0	0	0	0	0	0	0	0	0	0	3126.1	3075.61	2962.55	3067.3	3032.23	6326.53	9679.57
MARR	0	0	1029.53	2139.93	4290.36	4362.92	4363.15	4362.93	4364.68	4362.96	4362.92	4364.2	4363.27	4363.33	4362.92	4362.92	4362.92	4362.92
BOBR	0	0	0	0	0	0	0	0	0	0	0	1453.6	2908.98	4360.16	4363.62	4365.42	4364.76	4364.22
VARR	0	0	0	0	0	0	1513.22	1513.22	2970.95	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43	4456.43
KRVS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BURG	0	0	0	0	0	1702.3	2735.62	4263.16	4076.56	3679.59	4036.64	2960.45	3733.13	3284.3	3334.43	3652.92	3651.06	3662.65
DEVI	0	0	0	0	0	0	365.7	1134.27	978.61	840.26	1119.97	476.73	879.14	834.89	746.76	894.06	810.61	1044.36
PLEV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REPU	0	0	0	0	106.61	666.58	708.2	770.17	760.4	745.16	781.24	661.32	647.53	612.92	655.94	658.62	639.03	669.46
TRAI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	44.81
TOTAL	38885.64	39312.98	41419.62	43345.1	45170.3	47097.15	49164.22	50173.04	51004.59	51613.38	52732.25	53596.55	54517.13	54903.16	55412.23	55776.24	56301.16	56579.53

Fig - 5.3

BULGARIA: DEMAND - CAPACITY BALANCE

Power System Option Study (MINIMUM S-0)



BULGARIA: DEMAND - CAPACITY BALANCE

Power System Option Study (MINIMUM S-5)

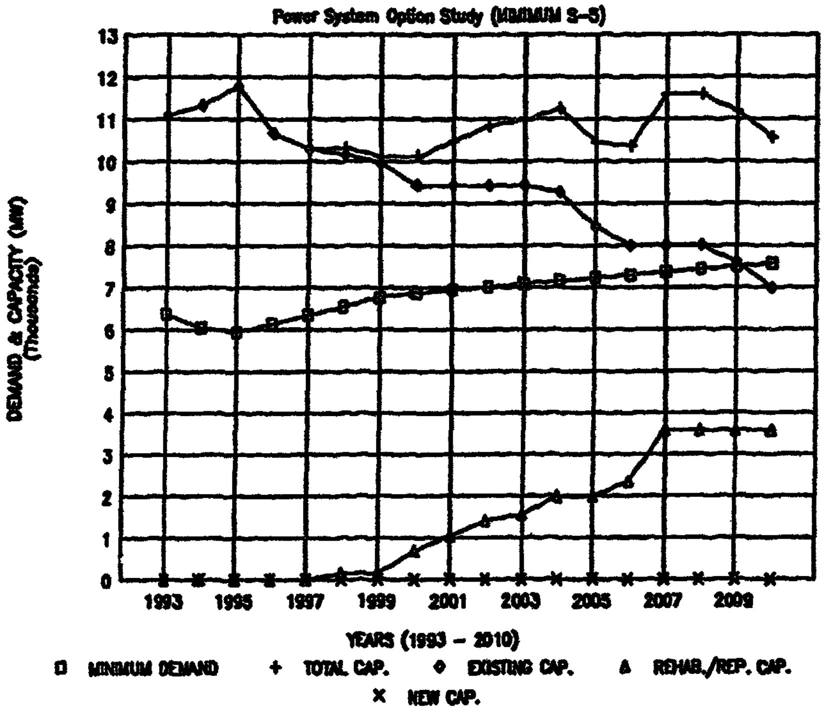
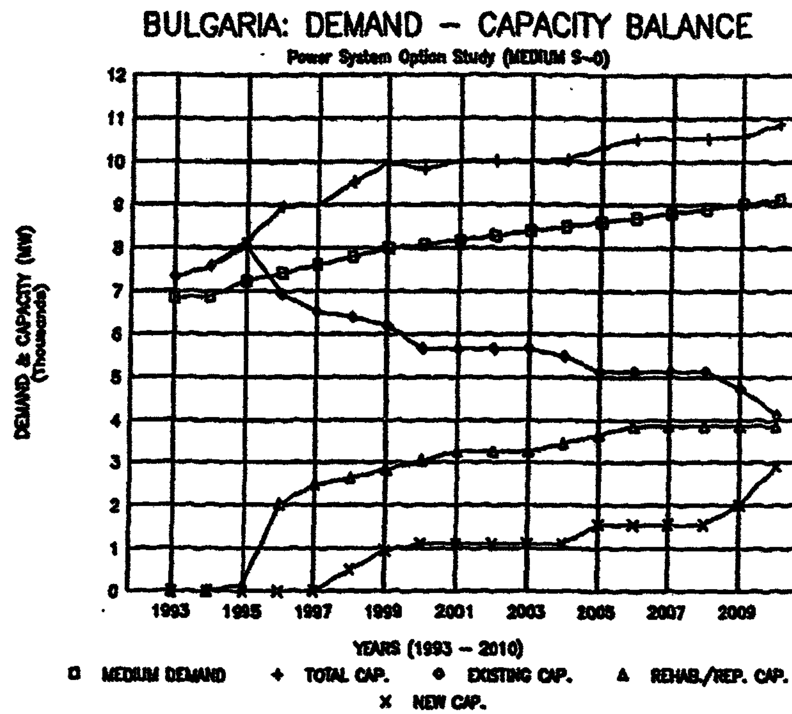
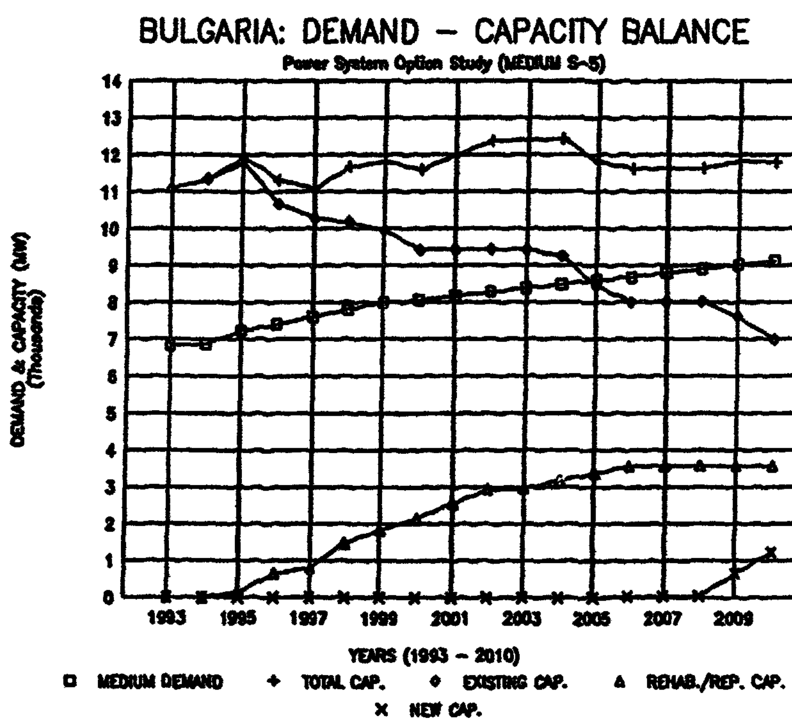


Fig - 5.4


BULGARIA: DEMAND - CAPACITY BALANCE
Power System Option Study (MEDIUM S-0)
DEMAND & CAPACITY (MW)
(Thousands)
0
1
2
3
4
5
6
7
8
9
10
11
12
1993
1995
1997
1999
2001
2003
2005
2007
2009
YEARS (1993 - 2010)
MEDIUM DEMAND
TOTAL CAP.
EXISTING CAP.
REHAB./REP. CAP.
NEW CAP.


BULGARIA: DEMAND - CAPACITY BALANCE
Power System Option Study (MEDIUM S-5)
DEMAND & CAPACITY (MW)
(Thousands)
0
1
2
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4
5
6
7
8
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1993
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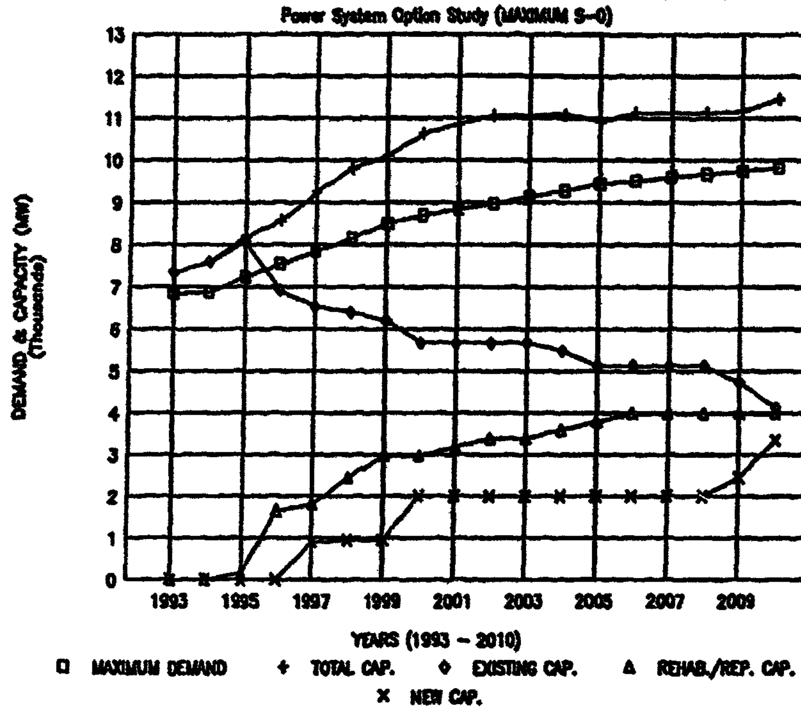
2003
2005
2007
2009
YEARS (1993 - 2010)
MEDIUM DEMAND
TOTAL CAP.
EXISTING CAP.
REHAB./REP. CAP.
NEW CAP.

Fig - 5.5

BULGARIA: DEMAND - CAPACITY BALANCE

Power System Option Study (MAXIMUM S-0)



BULGARIA: DEMAND - CAPACITY BALANCE

Power System Option Study (MAXIMUM S-5)

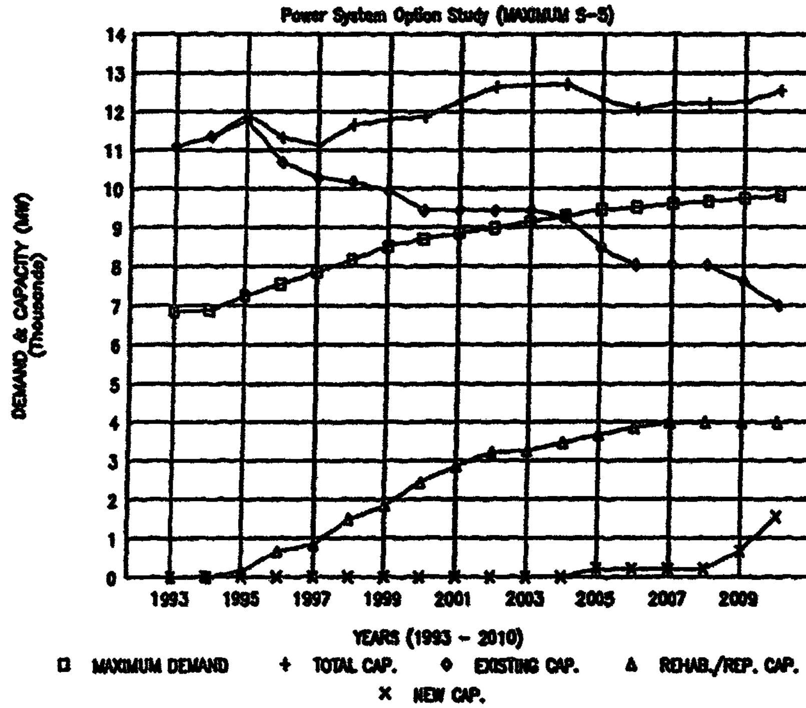


TABLE - 6.35 TOTAL SYSTEM COST (LOW REPOWERING OPTION)
LOAD FORECAST - MINIMUM
US$M

SCENARIO 0

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	23.30	473.50	208.02	43.30	245.02	993.14	993.14
1994	16.30	457.14	204.93	193.60	42.60	914.97	831.79
1995	11.70	432.49	166.96	291.90	2.33	905.36	748.25
1996	11.70	461.00	233.05	276.50	121.96	1104.21	829.61
1997	11.70	460.76	204.27	212.70	16.71	906.14	618.91
1998	0.00	483.73	185.49	162.50	14.30	866.01	537.72
1999	0.00	493.66	200.49	73.70	13.09	780.94	440.82
2000	0.00	507.50	211.16	41.00	15.72	775.38	397.89
2001	0.00	509.44	203.58	27.50	14.64	755.16	352.29
2002	0.00	509.62	198.85	29.50	15.92	753.89	319.72
2003	0.00	515.59	201.79	76.40	14.66	808.43	311.70
2004	0.00	518.25	204.00	155.90	13.76	891.92	312.61
2005	0.00	516.16	220.50	215.70	15.31	967.67	308.33
2006	0.00	522.96	208.64	360.60	13.06	1105.27	320.16
2007	0.00	527.72	212.76	404.60	12.03	1157.11	304.70
2008	0.00	532.06	218.58	397.60	14.69	1162.94	278.40
2009	0.00	500.30	246.28	177.80	28.43	952.80	207.36
2010	0.00	487.82	281.50	0.00	37.85	807.16	159.69
TOTAL	74.70	8909.72	3810.63	3161.00	652.30	16608.55	8273.08

SCENARIO 1

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	35.00	393.76	129.69	20.30	0.19	578.96	578.96
1994	30.50	362.33	135.33	55.30	1.79	585.26	532.05
1995	37.50	339.65	132.92	29.50	2.04	541.69	447.64
1996	97.50	355.35	147.67	75.50	14.59	690.91	519.09
1997	117.50	372.75	151.40	87.10	13.40	742.15	506.90
1998	50.00	391.66	155.00	62.20	14.19	673.07	417.93
1999	35.00	404.71	162.44	52.50	13.64	668.29	377.23
2000	20.00	404.00	186.68	46.40	38.73	695.81	357.06
2001	20.00	404.41	181.89	43.00	15.94	665.24	310.34
2002	75.00	404.66	177.08	35.90	1.56	694.19	294.41
2003	20.00	410.54	180.20	68.40	14.59	693.71	267.46
2004	20.00	412.23	181.96	74.30	14.50	702.98	246.39
2005	20.00	409.10	193.92	151.30	30.07	804.39	256.30
2006	20.00	414.61	187.15	232.50	13.50	867.76	251.36
2007	20.00	419.30	190.74	425.60	14.73	1070.37	281.66
2008	20.00	424.45	194.52	316.70	23.32	978.96	234.36
2009	20.00	440.56	201.23	83.40	22.51	767.69	167.07
2010	20.00	425.63	216.45	0.00	15.33	677.40	134.02
TOTAL	678.00	7189.69	3106.26	1660.50	294.60	13099.07	6180.64

SCENARIO 2

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	47.50	335.72	118.65	5.00	0.02	506.89	506.89
1994	54.30	307.39	127.78	23.30	1.55	514.32	467.56
1995	62.80	294.25	126.46	29.20	1.99	514.70	425.37
1996	113.80	307.11	141.16	92.30	14.26	668.62	502.35
1997	133.80	324.41	143.77	118.40	13.54	733.92	501.28
1998	57.50	391.66	155.00	62.20	14.19	680.57	422.58
1999	40.30	404.71	162.44	52.50	13.64	673.59	380.23
2000	23.80	404.00	186.68	46.40	38.73	699.61	359.01
2001	23.80	404.41	181.89	43.00	15.94	669.04	312.11
2002	78.80	404.66	177.06	35.90	15.57	712.00	301.96
2003	20.00	410.54	180.20	68.40	14.58	693.71	267.46
2004	20.00	412.23	181.96	74.30	14.50	702.98	246.39
2005	20.00	409.10	193.92	151.30	30.07	804.39	256.30
2006	20.00	414.61	187.15	232.50	13.50	867.76	251.36
2007	20.00	419.30	190.74	425.60	14.73	1070.37	281.66
2008	20.00	424.45	194.52	316.70	23.32	978.96	234.36
2009	20.00	440.56	201.23	83.40	22.51	767.69	167.07
2010	20.00	425.63	216.45	0.00	15.33	677.40	134.02
TOTAL	796.40	6934.73	3067.08	1860.40	277.96	12936.57	6018.16

SCENARIO 3

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	60.00	280.86	110.31	5.00	0.01	456.19	456.19
1994	76.10	253.99	120.71	23.30	1.27	477.37	433.97
1995	88.10	243.74	118.72	29.20	1.57	481.33	397.79
1996	190.00	253.29	134.53	92.30	13.82	623.94	468.76
1997	150.00	268.72	137.26	118.40	13.14	687.56	469.61
1998	65.00	391.66	155.00	62.20	14.19	688.07	427.24
1999	45.50	404.71	162.44	52.50	13.64	678.79	383.16
2000	27.50	404.00	186.68	46.40	38.73	703.31	360.91
2001	27.50	404.41	181.89	43.00	15.94	672.74	313.84
2002	82.50	404.66	177.06	35.90	15.57	715.70	303.53
2003	20.00	410.54	180.20	68.40	14.58	693.71	267.46
2004	20.00	412.23	181.96	74.30	14.50	702.98	246.39
2005	20.00	409.10	193.92	151.30	30.07	804.39	256.30
2006	20.00	414.61	187.15	232.50	13.50	867.76	251.36
2007	20.00	419.30	190.74	425.60	14.73	1070.37	281.66
2008	20.00	424.45	194.52	316.70	23.32	978.96	234.36
2009	20.00	440.56	201.23	83.40	22.51	767.69	167.07
2010	20.00	425.63	216.45	0.00	15.33	677.40	134.02
TOTAL	914.20	6868.47	3030.82	1860.40	276.41	12748.29	5853.83

SCENARIO 4

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	65.00	260.86	110.31	5.00	0.01	461.19	461.19
1994	63.10	253.99	120.71	20.00	1.27	459.07	417.34
1995	126.10	243.74	118.72	14.30	1.57	506.43	418.53
1996	160.00	253.29	134.53	64.00	13.82	625.64	470.05
1997	150.00	270.52	136.72	102.40	13.22	672.86	459.57
1998	77.50	335.01	147.45	27.50	14.44	601.90	373.73
1999	60.30	347.43	151.46	13.40	13.76	586.35	330.96
2000	43.60	360.37	156.17	41.00	16.02	617.36	316.60
2001	43.60	360.11	156.55	27.50	15.25	603.21	281.40
2002	96.60	360.16	157.80	11.60	16.65	645.24	273.64
2003	40.00	366.00	158.65	36.10	15.53	616.48	237.68
2004	40.00	370.45	160.06	41.90	14.78	627.19	219.63
2005	40.00	376.59	162.33	36.90	14.36	632.19	201.44
2006	40.00	382.24	162.69	56.60	13.66	654.41	189.56
2007	40.00	388.00	163.69	162.60	12.77	767.26	202.04
2008	40.00	393.42	165.01	220.40	15.24	834.07	199.67
2009	40.00	397.66	176.82	68.90	16.51	699.91	152.32
2010	40.00	396.53	195.67	0.00	18.77	650.97	128.79
TOTAL	1210.40	6138.42	2736.54	949.60	227.87	11261.73	5334.56

SCENARIO 5

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	85.60	260.86	110.31	5.00	0.01	461.79	461.79
1994	150.60	253.99	120.71	20.00	1.27	546.57	496.86
1995	190.00	243.74	118.72	14.30	1.57	568.33	469.69
1996	165.00	252.47	135.17	64.00	11.71	628.35	472.09
1997	90.00	270.57	136.78	102.40	13.12	612.86	418.59
1998	75.00	281.79	140.75	27.50	13.76	538.79	334.55
1999	60.00	295.14	144.04	13.40	13.49	526.06	296.95
2000	60.00	304.27	146.06	41.00	15.78	567.13	291.03
2001	115.00	307.57	147.20	27.50	14.99	612.25	285.62
2002	60.00	311.36	148.32	11.60	16.26	547.74	232.90
2003	67.50	316.09	149.36	36.10	15.18	584.18	225.23
2004	65.30	320.94	150.66	38.40	14.44	590.76	207.06
2005	63.60	352.61	157.20	31.50	14.93	620.24	197.63
2006	63.60	382.37	162.61	40.20	14.06	663.07	192.07
2007	63.60	388.14	163.66	123.30	12.87	751.77	197.98
2008	63.60	393.40	164.97	189.50	15.31	826.97	197.97
2009	63.60	401.24	176.91	98.90	15.07	753.92	164.07
2010	63.60	401.34	192.86	0.00	14.22	672.24	133.00
TOTAL	1566.60	5756.10	2666.35	853.80	218.00	11093.04	5294.46

TABLE - 5.36 TOTAL SYSTEM COST (LOW REPOWERING OPTION)
LOAD FORECAST - MEDIUM
US$M

SCENARIO 0

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	G.TOTAL	PV-EC.
1993	23.30	493.00	229.34	134.30	674.30	1554.23	1554.23
1994	16.30	499.66	254.59	759.40	732.47	2262.42	2056.74
1995	11.70	541.68	254.72	914.80	457.73	2180.84	1802.18
1996	11.70	506.68	303.75	392.80	823.75	2038.68	1531.69
1997	11.70	576.76	264.04	251.10	24.83	1128.43	770.73
1998	0.00	561.54	276.35	107.00	43.70	1010.58	627.49
1999	0.00	604.40	274.41	18.30	16.61	913.72	515.77
2000	0.00	593.05	291.10	75.90	91.71	1051.77	539.72
2001	0.00	599.32	287.89	153.50	45.30	1086.01	506.63
2002	0.00	604.38	285.54	271.50	22.64	1184.07	502.16
2003	0.00	611.34	291.55	302.40	36.59	1241.88	476.80
2004	0.00	614.53	295.70	178.80	57.68	1146.71	401.92
2005	0.00	607.97	305.73	292.20	17.02	1222.92	389.66
2006	0.00	617.98	302.46	506.50	16.19	1443.14	418.03
2007	0.00	625.64	308.35	687.30	15.27	1636.57	430.96
2008	0.00	631.91	314.47	423.50	22.47	1392.36	333.32
2009	0.00	631.47	340.36	96.50	24.73	1093.05	237.88
2010	0.00	595.78	375.50	0.00	21.69	992.97	196.45
TOTA	74.70	10537.10	5257.87	5565.80	3144.67	24580.14	13294.37

SCENARIO 1

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	35.00	438.71	148.00	52.90	2.13	676.73	676.73
1994	30.50	447.93	163.34	296.90	2.66	941.33	855.76
1995	37.50	466.67	166.48	337.20	3.40	1011.25	835.75
1996	97.50	477.57	215.42	229.00	71.47	1090.96	819.66
1997	117.50	501.97	196.96	271.40	22.50	1110.33	758.37
1998	50.00	513.96	203.60	139.30	35.79	942.64	585.30
1999	35.00	529.96	202.53	56.60	18.81	842.90	475.79
2000	20.00	521.29	225.14	148.10	43.99	958.52	491.87
2001	20.00	525.34	223.14	148.40	24.30	941.18	439.07
2002	75.00	528.37	220.14	190.80	20.20	1034.50	438.73
2003	20.00	536.74	224.79	137.60	31.07	950.20	386.34
2004	20.00	541.74	228.18	59.20	37.41	886.53	310.72
2005	20.00	516.92	238.58	79.10	13.59	868.20	276.63
2006	20.00	525.99	236.52	217.60	16.55	1016.67	294.49
2007	20.00	534.21	241.60	424.30	19.96	1240.09	326.56
2008	20.00	541.03	245.54	426.00	33.88	1266.45	303.18
2009	20.00	563.12	254.50	177.80	39.75	1055.16	229.63
2010	20.00	553.22	290.00	0.00	56.15	919.37	181.59
TOTAL	676.00	9264.73	3924.48	3392.20	493.63	17753.04	8666.49

SCENARIO 2

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	47.50	300.43	131.99	19.10	0.02	499.04	499.04
1994	54.30	315.41	144.02	138.20	2.07	654.00	594.54
1995	62.80	334.03	149.90	195.00	2.98	744.71	615.46
1996	113.80	364.96	168.54	293.20	19.99	960.49	721.63
1997	133.80	382.74	175.49	239.60	18.70	950.33	649.09
1998	57.50	473.60	198.78	171.30	19.64	920.79	571.74
1999	40.30	475.78	204.80	145.90	18.45	885.23	499.69
2000	23.80	495.72	227.85	98.20	20.02	865.60	444.19
2001	23.80	499.75	222.26	54.50	18.88	819.20	382.16
2002	78.80	504.79	220.30	13.10	20.60	837.59	365.22
2003	20.00	514.08	223.59	36.10	19.31	813.08	313.48
2004	20.00	520.86	226.34	38.60	18.48	824.29	288.91
2005	20.00	525.81	236.08	49.70	18.25	849.84	270.79
2006	20.00	531.81	232.98	127.00	17.59	929.38	269.21
2007	20.00	543.05	238.69	270.70	16.32	1088.76	286.70
2008	20.00	562.91	243.65	220.80	19.83	1057.19	253.08
2009	20.00	582.80	253.73	64.00	19.03	939.56	204.48
2010	20.00	606.25	273.12	0.00	20.63	919.99	182.02
TOTA	796.4	8524.6	3772.1	2175.0	290.8	15559.1	7401.4

SCENARIO 3

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	60.00	318.13	116.70	18.10	0.01	512.93	512.93
1994	78.10	323.24	132.10	74.30	2.09	609.83	554.39
1995	88.10	348.03	137.55	172.50	3.00	749.19	619.16
1996	130.00	367.49	153.22	369.40	19.66	1039.77	781.19
1997	150.00	380.63	156.54	355.40	18.11	1060.68	724.59
1998	65.00	512.68	203.36	141.50	57.27	979.80	608.38
1999	45.50	529.15	201.51	125.50	18.24	919.90	519.26
2000	27.50	522.04	223.60	161.80	86.65	1021.59	524.24
2001	27.50	527.31	220.48	206.50	52.23	1034.02	482.38
2002	82.50	531.21	217.64	113.40	28.77	973.51	412.86
2003	20.00	539.44	222.05	59.20	42.94	883.63	340.66
2004	20.00	516.27	225.39	36.10	17.56	815.32	285.76
2005	20.00	516.44	234.95	88.70	51.86	911.95	290.58
2006	20.00	526.28	233.15	334.80	28.00	1142.23	330.66
2007	20.00	534.01	237.59	528.70	44.82	1365.12	359.46
2308	20.00	541.03	245.54	426.00	33.88	1266.45	303.18
2009	20.00	563.12	254.50	177.80	39.75	1055.16	229.63
2010	20.00	553.22	290.00	0.00	56.15	919.37	181.59
TOTAL	914.20	8649.92	3705.88	3389.70	600.97	17260.67	8061.46

SCENARIO 4

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	65.00	318.13	116.70	12.60	0.01	512.43	512.43
1994	63.10	323.24	132.10	39.00	2.09	559.53	508.66
1995	128.10	348.03	137.55	56.70	3.00	673.39	556.52
1996	160.00	367.49	153.22	199.90	19.66	900.27	676.38
1997	150.00	380.63	156.54	273.70	18.11	979.18	668.79
1998	77.50	457.56	182.02	109.50	25.37	851.94	528.90
1999	60.30	473.11	181.26	26.80	18.34	759.81	428.89
2000	43.80	468.26	199.96	74.10	36.85	823.00	422.33
2001	43.80	472.45	198.47	86.10	22.17	822.99	383.93
2002	98.80	475.64	195.86	133.50	20.90	924.69	392.16
2003	40.00	484.07	200.30	160.70	20.90	905.96	349.29
2004	40.00	485.57	205.96	215.10	19.89	966.56	338.77
2005	40.00	486.13	214.44	145.70	60.85	947.12	301.78
2006	40.00	495.85	212.45	134.80	33.18	916.28	265.41
2007	40.00	478.34	218.90	256.20	16.06	1009.51	265.83
2008	40.00	485.44	223.31	322.40	23.01	1094.16	261.93
2009	40.00	506.59	232.11	164.70	26.65	970.05	211.11
2010	40.00	518.92	251.23	0.00	37.34	847.49	167.67
TOTA	1210.40	8025.64	3412.43	2411.50	404.37	15464.33	7240.89

SCENARIO 5

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	85.60	318.13	116.70	12.60	0.01	533.03	533.03
1994	150.60	323.24	132.10	35.70	2.09	643.73	585.21
1995	190.00	348.03	137.55	22.00	3.00	700.59	579.00
1996	165.00	365.22	154.33	64.40	19.83	768.78	577.60
1997	90.00	384.50	156.14	71.10	18.14	719.88	491.69
1998	75.00	396.89	158.99	27.50	19.28	677.66	420.77
1999	60.00	409.58	163.65	19.20	17.58	670.01	378.20
2000	60.00	415.14	172.96	53.60	21.02	722.73	370.88
2001	115.00	419.05	171.75	64.20	19.80	789.80	368.46
2002	60.00	422.60	171.23	105.10	21.21	780.14	330.86
2003	67.50	431.59	174.04	211.40	20.07	904.60	348.76
2004	65.30	437.78	177.07	338.50	19.42	1038.07	363.84
2005	63.80	454.98	206.81	225.30	34.13	985.03	313.86
2006	63.80	497.38	212.10	290.60	18.51	1082.38	313.53
2007	63.80	507.13	216.50	348.10	24.01	1159.54	305.34
2008	63.80	515.23	220.75	238.30	41.15	1079.23	258.38
2009	63.80	508.05	231.33	60.90	17.58	881.06	191.74
2010	63.80	523.11	247.02	0.00	36.31	870.24	172.17
TOTAL	1566.80	7677.65	3221.03	2187.90	353.12	15006.50	6903.26

TABLE - 5.37 TOTAL SYSTEM COST (LOW REPOWERING OPTION)
LOAD FORECAST - MAXIMUM
US$M

SCENARIO 0

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	23.30	473.50	208.02	173.30	674.30	1552.41	1552.41
1994	16.30	457.14	204.93	1016.70	732.47	2427.54	2206.85
1995	11.70	432.49	166.96	1252.20	457.73	2321.08	1918.25
1996	11.70	461.61	198.23	682.50	533.06	1877.10	1410.29
1997	11.70	468.57	179.18	482.00	41.14	1182.58	794.06
1998	0.00	497.48	187.53	280.70	27.20	992.91	616.52
1999	0.00	517.53	196.65	130.90	19.22	864.31	487.88
2000	0.00	546.62	219.13	185.20	26.45	977.39	501.56
2001	0.00	538.66	214.18	183.00	21.76	957.60	446.73
2002	0.00	529.38	211.01	219.80	23.66	983.84	417.25
2003	0.00	538.58	213.56	152.20	21.70	926.05	357.03
2004	0.00	539.83	214.40	97.90	25.38	877.48	307.55
2005	0.00	547.69	222.77	185.10	26.45	982.01	312.90
2006	0.00	540.83	215.88	385.60	17.66	1159.97	336.00
2007	0.00	549.98	218.90	517.90	18.66	1302.40	342.98
2008	0.00	558.59	222.49	439.10	26.99	1243.58	297.70
2009	0.00	574.87	229.03	177.80	23.94	999.10	217.43
2010	0.00	591.62	248.20	0.00	30.31	850.97	169.38
TOTA	74.70	9354.93	3522.84	6541.90	2748.06	22458 32	12691.73

SCENARIO 1

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	35.00	438.71	148.00	55.40	2.13	679.23	679.23
1994	30.50	447.93	163.34	327.40	2.66	971.83	883.49
1995	37.50	466.67	181.18	434.60	3.40	1123.35	928.39
1996	97.50	488.13	214.11	322.80	63.75	1186.29	891.28
1997	117.50	520.88	203.25	378.10	29.35	1249.58	853.48
1998	50.00	554.07	209.92	344.30	24.13	1182.42	734.19
1999	35.00	571.91	232.10	185.70	30.82	1055.54	595.82
2000	20.00	585.03	246.77	161.80	43.19	1056.80	542.30
2001	20.00	592.33	246.55	206.50	28.42	1093.81	510.27
2002	75.00	598.71	245.84	113.40	23.90	1056.84	448.20
2003	20.00	612.20	252.66	59.20	36.48	980.54	378.04
2004	20.00	593.39	258.46	71.00	19.99	962.84	337.47
2005	20.00	597.78	269.48	194.70	63.21	1145.17	364.89
2006	20.00	605.15	267.26	502.80	30.81	1426.01	413.06
2007	20.00	611.43	270.97	622.30	42.00	1566.69	412.56
2008	20.00	615.84	277.61	439.10	30.48	1383.04	331.09
2009	20.00	612.45	301.44	177.80	27.82	1139.50	247.99
2010	20.00	601.07	336.54	0.00	33.13	990.74	196.01
TOTAL	678.00	10113.69	4325.46	4596.90	536.17	20250.21	9747.76

SCENARIO 2

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	47.50	377.73	126.69	23.40	0.08	575.40	575.40
1994	54.30	384.64	140.87	111.30	2.23	693.34	630.31
1995	62.80	405.56	146.46	279.80	3.05	897.67	741.87
1996	113.80	435.99	172.52	561.00	20.78	1304.09	979.78
1997	133.80	465.06	181.12	542.80	22.43	1345.22	918.80
1998	57.50	554.07	209.92	344.30	24.13	1189.92	738.85
1999	40.30	571.91	232.10	185.70	30.82	1060.84	598.81
2000	23.80	585.03	246.77	161.80	43.19	1060.60	544.25
2001	23.80	592.33	246.55	206.50	28.42	1097.61	512.04
2002	78.80	598.71	245.84	113.40	23.90	1060.64	449.82
2003	20.00	612.20	252.66	59.20	36.48	980.54	378.04
2004	20.00	593.39	258.46	71.00	19.99	962.84	337.47
2005	20.00	597.78	269.48	194.70	63.21	1145.17	364.89
2006	20.00	605.15	267.26	502.80	30.81	1426.01	413.06
2007	20.00	611.43	270.97	622.30	42.00	1566.69	412.56
2008	20.00	615.84	277.72	439.10	30.48	1383.15	331.12
2009	20.00	612.45	301.44	177.80	27.82	1139.50	247.99
2010	20.00	601.07	336.54	0.00	33.13	990.74	196.01
TOTA	796.40	9820.36	4183.35	4596.90	482.95	19879.96	9371.08

SCENARIO 3

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	60.00	318.13	116.70	15.10	0.01	509.93	509.93
1994	78.10	323.24	132.10	91.90	2.09	627.43	570.39
1995	88.10	348.03	137.55	260.90	3.00	837.58	692.22
1996	130.00	376.72	155.74	581.20	20.20	1263.85	949.55
1997	150.00	400.20	160.42	569.20	18.69	1298.50	886.89
1998	65.00	554.07	209.92	344.30	24.13	1197.42	743.50
1999	45.50	571.91	232.10	185.70	30.82	1066.04	601.75
2000	27.50	585.03	246.77	161.80	43.19	1064.30	546 15
2001	27.50	592.33	246.55	206.50	28.42	1101.31	513.77
2002	82.50	598.71	245.84	113.40	23.90	1064.34	451.39
2003	20.00	612.20	252.66	59.20	36.48	980.54	378.04
2004	20.00	593.39	258.46	71.00	19.99	962.84	337.47
2005	20.00	597.78	269.48	194.70	63.21	1145.17	364.89
2006	20.00	605.15	267.26	502.80	30.81	1426.01	413.06
2007	20.00	611.43	270.97	622.30	42.00	1566.69	412.56
2008	20.00	615.84	277.61	439.10	30.48	1383.04	331.09
2009	20.00	612.45	301.44	177.80	27.82	1139.50	247.99
2010	20.00	601.07	336.54	0.00	33.13	990.74	196.01
TOTAL	914.20	9517.69	4118.09	4596.90	478.36	19625.24	9146.66

SCENARIO 4

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	65.00	318.13	116.70	12.60	0.01	512.43	512.43
1994	63.10	323.24	132.10	69.00	2.09	589.53	535.94
1995	126.10	348.03	137.55	169.60	3.00	786.29	649.82
1996	160.00	376.72	155.74	362.60	20.20	1075.25	807.85
1997	150.00	400.20	160.42	342.30	18.69	1071.60	731.92
1998	77.50	497.55	187.67	121.60	21.76	906.08	562.61
1999	60.30	526.57	193.91	22.10	20.27	823.15	464.65
2000	43.80	530.27	220.45	60.90	59.43	914.85	469.46
2001	43.80	537.04	220.65	119.20	37.93	958.62	447.20
2002	98.80	544.41	220.85	184.40	28.47	1076.93	456.72
2003	40.00	558.11	227.29	130.80	51.20	1007.41	388.40
2004	40.00	573.34	222.20	143.20	21.05	999.78	350.42
2005	40.00	579.87	232.83	180.00	35.92	1068.62	340.50
2006	40.00	586.44	230.74	314.50	21.41	1193.10	345.60
2007	40.00	593.02	234.03	488.00	25.43	1380.48	363.52
2008	40.00	597.86	236.53	493.30	36.44	1404.13	336.14
2009	40.00	578.05	258.38	177.80	37.76	1091.99	237.65
2010	40.00	566.49	293.14	0.00	46.67	946.30	187.22
TOTA	1210.40	9035.33	3881.19	3391.90	487.71	17806.54	8188.04

SCENARIO 5

YEAR	NUCLEAR	FUEL	O&M	CAPITAL	ENS	TOTAL	PV
1993	85.60	318.13	116.70	12.60	0.01	533.03	533.03
1994	150.60	323.24	132.10	49.10	2.09	657.13	597.39
1995	190.00	348.03	137.55	57.90	3.00	736.49	608.67
1996	165.00	374.67	156.74	100.50	20.41	817.32	614.07
1997	90.00	400.04	160.61	95.50	19.06	765.21	522.65
1998	75.00	433.86	165.66	76.70	20.54	771.76	479.20
1999	60.00	460.15	178.83	53.80	20.42	773.20	436.45
2000	60.00	462.59	206.74	60.90	45.76	835.99	429.00
2001	115.00	469.01	205.99	139.20	29.74	958.94	447.35
2002	60.00	475.56	205.86	296.10	24.35	1061 87	450.34
2003	67.50	490.69	213.18	377.40	38.36	1187.12	457.69
2004	65.30	501.01	206.82	358.40	20.91	1152.43	403.92
2005	63.80	544.65	224.79	240.30	23.44	1096.98	349.53
2006	63.80	587.20	229.78	304.90	20.20	1205.87	349.30
2007	63.80	594.21	233.41	370.90	18.67	1280.99	337.39
2008	63.80	599.86	236.26	388.90	23.17	1311.79	314.03
2009	63.80	581.91	253.32	177.80	37.09	1114.42	242.53
2010	63.80	570.77	268.13	0.00	45.31	968.01	191.52
TOTAL	1566.80	8635.35	3652.97	3160.90	412.52	17228.57	7763.99

BULGARIA

REPOWERING OF EXISTING DISTRICT HEATING PLANTS AND INDUSTRIAL COGENERATION PLANTS IN BULGARIA

Introduction

1. This annex is prepared in order to facilitate the understanding of the Repowering Concept and to describe the specific meanings of terminologies used in the main body of the report.

Repowering

2. Repowering in this report means changes to the existing thermodynamic cycle through the addition of a topping gas turbine, the capacity of which is determined or estimated in such a way that the waste heat from it will generate steam consistent with the rated conditions of the boiler or boilers that now supply steam to the existing steam cycle (see Figure 6.1). The purpose of such Repowering is to efficiently increase, both technically and economically, the net electric generating capacity of the existing plant. Recent advances in gas turbine technology, especially the use of aircraft-derived engines for power generation are expected to obtain a substantial share of this Repowering/ Cogeneration market. For example, one of the latest additions to this gas turbine selection is the LM 6000. Based on a stand-alone operation, it has an output of 40 MW electrical output, 42% thermal efficiency, and an exhaust gas temperature of nearly 840 degrees fahrenheit which is high enough to produce steam for many process purposes.

Advantages of Repowering

3. Briefly, the following are some of the known advantages of repowering existing cogeneration facilities:

- Increased system-wide energy conversion efficiency, resulting in reduced demand for non-renewable fossil fuels (e.g natural gas);
- Improved air quality through reduced air emissions;
- Reduced production costs for electric generation, resulting in future utility rate reductions;
- Enhanced environmental quality due to minimizing the need for new electric generating and transmission facilities;
- Retained generating capacity in or near load centers to sustain high quality electric service (e.g. voltage support, frequency control, load response) and minimize transmission losses;
- High ratio of power output to occupied ground space;

- Rapid start-up characteristics; a cold start takes less than two hours while a hot start takes less than thirty minutes;

- Low installation costs;

- Cooling water requirements are less - by about half - compared to fossil-fuel-fired steam plants;

- High availability and reliability;

- Lower erection/commissioning periods.

Estimated Capacities

4. Because of the limited scope of the study, the gas turbine capacities were estimated by prorating the parameters of standard gas turbine/heat recovery steam generator configurations. Therefore, the term **Estimated Capacities** was used rather than "calculated capacities". But for the purposes of this study which entails the broad examination (birds-eye view) of several generation scenarios, this prorating method is not expected to contribute sufficient inaccuracies which may skew the outcome of the study.

Maximum Repowering Potential

5. Maximum Repowering Potential was determined by assuming that any plant that is currently listed as operating and uses or has the potential to use natural gas as fuel could be converted to gas turbine repowering. It was beyond the scope of this study to examine each one of these plants in detail, that is perform pre-feasibility studies, to identify realistic candidates in the true technical and economic sense. Therefore, this maximum potential should be considered as a first step in identifying opportunities for repowering and the estimated maximum potential may not be realizable. This point has been made very clear in the main body of the text (page 29).

Repowering Design Parameters

6. Some of the parameters and details that have a major influence in determining whether or not to repower an existing cogeneration facility are the following:

- Type of facility- These could be district heating facilities with or without ability to produce steam for industrial purposes with back pressure and/or condensing steam turbines; existing steam plants in refineries, petrochemical/chemical plants, metallurgical plants such as Kremitovski, fertilizer plants, etc. - In the district heating plant category, there are several units at Sofia, Kostov, Plovdiv, Shumen, etc. which offer the potential for repowering and it is anticipated that the continued use of these units is essential for heat supply to the population. During the current political and economic transition, it has been noted that several industrial plants in Bulgaria including the Burgas refinery, are operating at reduced utilization factors, because of lack of feed stocks and the need for capital for rehabilitation and modernization. Studies need to be done to confirm that these plants are viable. Therefore, the design basis for repowering cogeneration plants in these industrial plants should be based on the long term economic and industrial developmental needs of the country. While developing this design basis such factors such as end user efficiency (especially thermal energy) improvements and associated costs need to be introduced, while performing a detailed optimization study.

- Age of existing facility - Initial examination of data indicate that many units in the above facilities could undergo life extension through rehabilitation and such life extension would let the plant operate at least another twenty years. The life extension costs would only apply to such systems as overhauling steam turbines and introduction of modern instrument and controls.

- Fuel Availability and Price - Natural gas is the desired fuel and its availability and the security of supply is addressed in other parts of this report.

- Electric Energy Price - The price paid for electric power by the utility is sufficient to justify repowering.

- Ratio of Electric to Thermal Power - A detailed profile of current and future thermal energy demand is necessary for optimizing electrical power generation.

- Site limitations - Generally, required floor area for repowering is small. A typical GE PG-7111EA gas turbine package with heat recovery steam generator, deaerator, feed pump will require approximately 103 feet by 230 feet floor area. A typical Westinghouse two W501D combined cycle unit including steam turbine requires a site area of approximately 220 ftX 380 ft floor area.

- Regulatory and Licensing requirements -

- Capital cost for repowering i.e. capital costs associated with installation of gas turbines, heat recovery steam generators, life extension costs associated with existing steam turbine systems and other associated ancillary systems. U.S. experience indicates capital costs for repowering based on additional incremental capacity in the broad range of US$300/KW to US$500/KW. The estimated capital costs for this study are within this range. The values used are closer to the higher end of this cost range.

- Financial factors (interest rates, payment term, etc.) -

Repowering Examples

7. The following examples demonstrate this repowering concept applied to the existing district heating facilities at Shumen, Sofia and the existing cogeneration facility at the Burgas refinery. These examples are not pre-feasibility studies as such studies require plant audits thorough site visits and examination of other pertinent data and establishment of design bases, including economic evaluation factors. Selection of type and number of gas turbines and heat recovery steam generators are all functions of these and the above factors and, therefore, the type and number of gas turbines selected in the following examples are for purposes of demonstration of the concept of repowering. In addition, gas turbines were selected, based on approximate matching of the existing rated steam turbine inlet conditions.

Example 1 - Shumen District Heating Plant

8. There are three installed steam turbine units in this plant. Each unit was matched with a gas turbine and heat recovery steam generator consistent with the rated conditions of the existing steam turbine units. See attached Table 6.2 and simplified heat balances (Figures 6.2.1, 6.2.2, 6.2.3) for technical information. Simple economic analyses were carried out, assuming several operating scenarios (number of hours of full load operation) and results are shown for ten and twenty year pay back periods. The costs do not include operating and maintenance costs exclusive of fuel costs. Calculated electricity rates are for increased electric generating capacity. The results show that for all three operating scenarios the repowering option presents itself as an attractive alternative.

Example 2 - Burgas Refinery Cogeneration Plant

9. Methodology used is same as above. See attached Table 6.3 and Figures 6.3.1 and 6.3.2 for technical and economic parameters. It is anticipated that this refinery will be modernized and is expected to operate at least 6,000 hours per year. In addition, this complex is expected to supply the repowered plant a portion or all of the fuel which is produced as a byproduct. After revamping of this refinery, it may be anticipated that at least two of the existing four turbine units will be in operation. The conclusions are similar to the above Example 1.

Example 3 - Sofia District Heating Plant

10. There are two turbine units in this plant that offer the potential for repowering. The attached Table 6.4 and heat balances shown in Figures 6.4.1 and 6.4.2 indicate conclusions similar to those discussed above.

Comparison between Estimated and Calculated Capacities for the above examples

11. Table 6.1 below shows the comparison between the estimated capacities used for the study and calculated capacities for the above examples. The comparison shows that the differences between the two methods is within the margin of accuracy needed for this study.

Table 6.1

Plant Name, Unit	Estimated Capacity (MW) 1	Calculated Capacity (MW) 2
Shumen Unit 1	54	53
Shumen Unit 2	63	66
Shumen Unit 3	46	44
Burgas Units 1 & 2 (each)	295	299
Burgas Units 3 & 4 (each)	253	246
Sofia Unit 6	243	256
Sofia Unit 8	146	154

Table 6.2 - SHUMEN DISTRICT HEATING PLANT - EXISTING CONFIGURATION

	Boiler Type	Turbine	Year Installed	Rated Turbine Steam Flow Tons/hr.	Rated Turbine Inlet Pressure Atmosphere	Rated Turbine Inle emperatur Deg. C	Rated Extraction Flow (Pt.1) Tons/hr.	Rated Extraction Flow(Pt.2) Tons/hr.	Rated Electric Capacity MW.	1991 Thermal Energy 10^3 giga-calories	1991 Electric Generation gigawatt-hours	1991 Availability %
Unit 1	(2) BK3-75	P-6-35/10/5	1976	80.5	35	450	50	30.5	6	Total	Total	67.6
Unit 2	(3) ⊼K-35	P-6-35/11	1980	93.5	35	450	93.5	None	6	563	54	12.15
Unit 3	(2) △KB-13	P-6-35/6	1980	66.6	35	450	66.6	None	6			79

Notes:

Number in paranthesis for Boiler indicates number of boilers and the following information corresponds to type of boiler

First letter in the turbine indicates type of turbine and the second number indicates generator capacity, the third number is the inlet pressure to the turbine and the following numbers correspond to extraction pressures.

The availability for one of the units is low and it is assumed that either the unit is undergoing rehabilitation or the reduced steam demand due to reduced industrial activity.

REPOWERED CONFIGURATION (NOT OPTIMIZED)

Remove existing boilers and replace with heat recovery steam generators (see attached heat balances)

	Gas turbine	Gas turbine Generator Capacity MW	Steam Turbine	Stm. turbine Generator Capacity MW	Total Capacity MW	Heat Rate Kcal/Kwh	Installation Costs $ Million
Unit 1	1 x ABB-GT-8	46.46	P6-35/10/5	6	52.46	1401	22
Unit 2	1 x KWU - V64.3	59.46	P6-35/11	6	65.46	1281	27
Unit 3	1 x GE - PG6541-B	38.06	P6-35/6	6	44.06	1376	18

ECONOMICS (PRELIMINARY)

The economic analysis is simple analysis based on present value method

Additional Fuel Cost is cost of fuel required to produce additional electric power through Repowering
Electricity Cost is the production cost for additional electricity produced through Repowering

	Installed Cost MM $	Hours per year	Thermal Energy 10^3 giga-calories	Electric Energy gigawatt-hours	Additional Fuel Cost MM $/year	Levelized Electricity Cost(2) $/kwhr	Levelized Electricity Cost(3) $/kwhr	Hours per year	Thermal Energy 10^3 giga calories	Electric Energy gigawatt-hours	Additional Fuel Cost MM $/year	Levelized Electricity Cost(2) $/kwhr	Levelize Electricit Cost(3) $/kwhr
Unit 1	22	3600	178.54	188.8	3.27	0.041	0.035	6000	297.57	314.7	5.45	0.032	0.029
Unit 2	27	3600	210.29	235.62	3.9	0.039	0.033	6000	350.48	392.7	6.5	0.031	0.027
Unit 3	18	3600	144.81	158.6	2.66	0.041	0.035	6000	241.02	264.3	4.43	0.032	0.029

Notes:

(2) Based on 10 year life and 10% discount rate and $4 per million BTU of fuel cost
(3) Based on 20 year life and 10% discount rate and $4 per million BTU of fuel cost

Installed cost is present day and does not include interest during construction
Installed costs were calculated using published gas turbine generator cost data and historical inhouse data for heat recovery steam generators and construction costs.

Table 8.3 - BURGAS DISTRICT HEATING PLANT - EXISTING CONFIGURATION

In general, most refinery and petrochemical complexes produce power plant fuel as a byproduct from many of their units such as FCC. No credit is taken for this fuel since fuel quality and quantity is not known. Therefore, the foregoing economic analysis is conservative.

	Boiler Type	Turbine	Year Installed	Rated Turbine Steam Flow Tons/hr.	Rated Turbine Inlet Pressure Atmospheres	Rated Turbine Inlet Temperature Deg. C	Rated Extraction Flow (Pt.1) Tons/hr.	Rated Extraction Flow(Pt.2) Tons/hr.	Rated Electric Capacity MW.	1991 Thermal Energy 10^3 giga-calories	1991 Electric Generation gigawatt-hours
Unit 1	N.A.	P-50-130/10	N.A.	404.5	130	540	344	None	50	N.A.	N.A.
Unit 2	N.A.	P-50-130/10	N.A.	404.5	130	540	344	None	50	N.A.	N.A.
Unit 3	N.A.	ПТ-60-90/10(1)	N.A.	324	90	540	140	None	60	N.A.	N.A.
Unit 4	N.A.	ПТ-60-90/10(1)	N.A.	324	90	540	140	None	60	N.A.	N.A.

Notes:
Number in paranthesis for boiler indicates number of boilers and the following information corresponds to type of boiler
First letter in the turbine indicates type of turbine and the second number indicates generator capacity, the third number is the inlet pressure to the turbine and the following numbers correspond to extraction pressures.
(1)ПТ-60-90/10 has been approximated by ПТ-50-90/10/1.2 without 1.2 atm. extraction

REPOWERED CONFIGURATION (NOT OPTIMIZED)

Remove existing boilers and replace with heat recovery steam generators (see attached heat balances)

	Gas turbine	Steam turbine	Gas turbine Generator Capacity, MW	Stm. turbine Generator Capacity, MW	Total Capacity MW	Heat Rate Kcal/KWh	Installation Costs $ Million
Unit 1	3xGE - PG7111EA	P-50-130/10	248.5	50	298.5	1551	103.73
Unit 2	3xGE - PG7111EA	P-50-130/10	248.5	50	298.5	1551	103.73
Unit 3	4 x ABB-8	ПТ-60-90/10	185.8	60	245.8	1803	79.02
Unit 4	4 x ABB-8	ПТ-60-90/10	185.8	60	245.8	1803	79.02

ECONOMICS (PRELIMINARY)

The economic analysis is simple analysis based on present value method

Additional Fuel Cost is cost of fuel required to produce additional electric power through Repowering.
Electricity Cost is the production cost for additional electricity produced through Repowering.

	Installed Cost MM $	Hours per year	Thermal Energy 10^3 giga-calories	Electric Energy gigawatt-hours	Additional Fuel Cost MM $/year	Levelized Electricity Cost(2) $/kwhr	Levelized Electricity Cost(3) $/kwhr	Hours per year	Thermal Energy 10^3 giga-calories	Electric Energy gigawatt-hours	Additional Fuel Cost MM $/year	Levelized Electricit Cost(2) $/kwhr	Levelized Electricit Cost(3) $/kwhr
Unit 1	104	6000	1251.5	1791	31.1	0.032	0.029	3600	750.9	1074.6	18.6	0.04	0.034
Unit 2	104	6000	1251.5	1791	31.1	0.032	0.029	3600	750.9	1074.6	18.6	0.04	0.034
Unit 3	79	6000	503	1474.8	22.6	0.031	0.028	3600	301.8	884.9	13.6	0.039	0.034
Unit4	79	6000	503	1474.8	22.6	0.031	0.028	3600	301.8	884.9	13.6	0.039	0.034

Notes:
(2) Based on 10 year life and 10% discount rate and $4 per million BTU of fuel cost
(3) Based on 20 year life and 10% discount rate and $4 per million BTU of fuel cost
Installed cost is present day and does not include interest during construction
Installed costs were calculated using published gas turbine generator cost data and historical in-house data for heat recovery steam generators and construction costs.

Table 6.4 – SOFIA DISTRICT HEATING PLANT – EXISTING CONFIGURATION

	Boiler Type	Turbine	Year Installed	Rated Turbine Steam Flow Tons/hr.	Rated Turbine inlet Pressure Atmosphere	Rated Turbine inlet Temperature Deg. C	Rated Extraction Flow (Pt.1) Tons/hr.	Rated Extraction Flow(Pt.2) Tons/hr.	Rated Electric Capacity MW.	1991 Thermal Energy 10^3 giga-calories Total	1991 Electric Generation gigawatt-hours Total	1991 Availability %
Unit 1	ТП-170	ПТ-50-90/10/1.2(1)	1985	324	100	540	140	100	50	2326	484.7	77
Unit 8		P-25-9010	1985	203	100	540	170	33	25			66

Notes:

Number in paranthesis for Boiler indicates number of boilers and the following information corresponds to type of boiler

First letter in the turbine indicates type of turbine and the second number indicates generator capacity, the third number is the inlet pressure to the turbine and the following numbers correspond to extraction pressures.

(1) Turbine ПТ-50-90/13/1.2 (reported) is approximated by ПТ-50-90/10/1.2

REPOWERED CONFIGURATION (NOT OPTIMIZED)

Remove existing boilers and replace with heat recovery steam generators (see attached heat balances)

	Gas turbine	Steam Turbine	Gas turbine Generator Capacity, MW	Stm. turbine Generator Capacity, MW	Total Capacity MW	Heat Rate Kcal/Kwhr	Installation Costs $ Million
Unit 1	4 x ABB-8	ПТ-50-90/10/1.2	185.8	50	235.8	1606	79
Unit 8	1 x Mitsubishi-MW701	P-25-9010	128.95	25	153.95	1387	42

ECONOMICS (PRELIMINARY)

The economic analysis is simple analysis based on present value method

Additional Fuel Cost is cost of fuel required to produce additional electric power through Repowering
Electricity Cost is the production cost for additional electricity produced through Repowering

	Installed Cost MM $	Hours per year	Thermal Energy 10^3 giga-calories	Electric Energy gigawatt-hours	Additional Fuel Cost MM $/year	Levelized Electricity Cost(2) $/kwhr	Levelized Electricity Cost(3) $/kwhr	Hours per year	Thermal Energy 10^3 giga-calories	Electric Energy gigawatt-hours	Additional Fuel Cost MM $/year	Levelized Electricity Cost(2) $/kwhr	Levelized Electricity Cost(3) $/kwhr
Unit 1	79	6000	851.1	1414.8	22.6	0.031	0.029	3600	510.7	848.9	13.6	0.039	0.034
Unit 8	42	6000	764.06	923.7	15.73	0.029	0.027	3600	458.4	554.2	9.44	0.035	0.031

Notes:

(2) Based on 10 year life and 10% discount rate and $4 per million BTU of fuel cost

(3) Based on 20 year life and 10% discount rate and $4 per million BTU of fuel cost

Installed cost is present day and does not include interest during construction
Installed costs were calculated using published gas turbine generator cost data and historical inhouse data for heat recovery steam generators and construction costs.

TYPICAL REPOWERING PROJECT

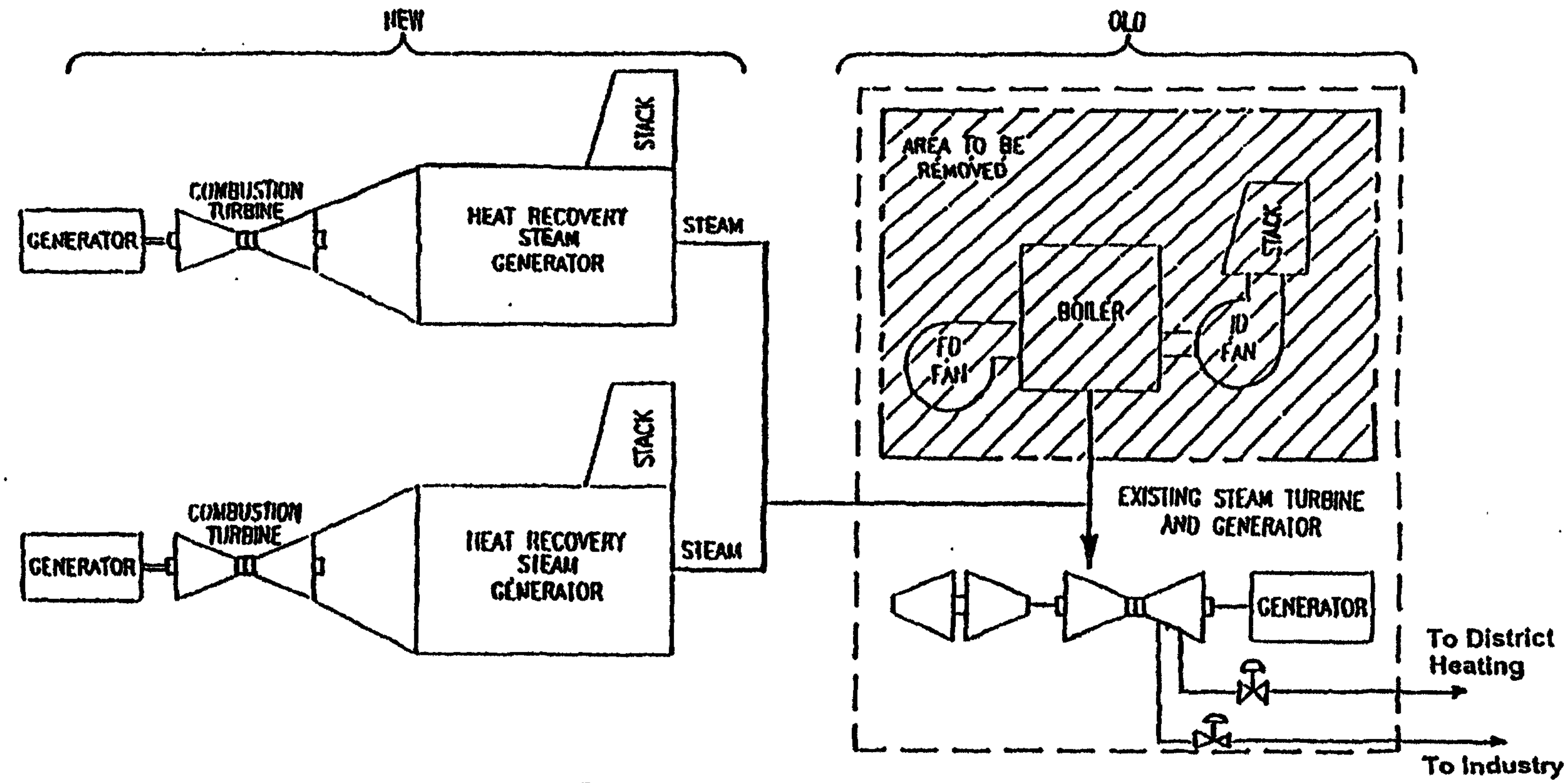


Figure 6.1

Figure 6.2.1

PLANT → SHUMEN   UNIT → 1

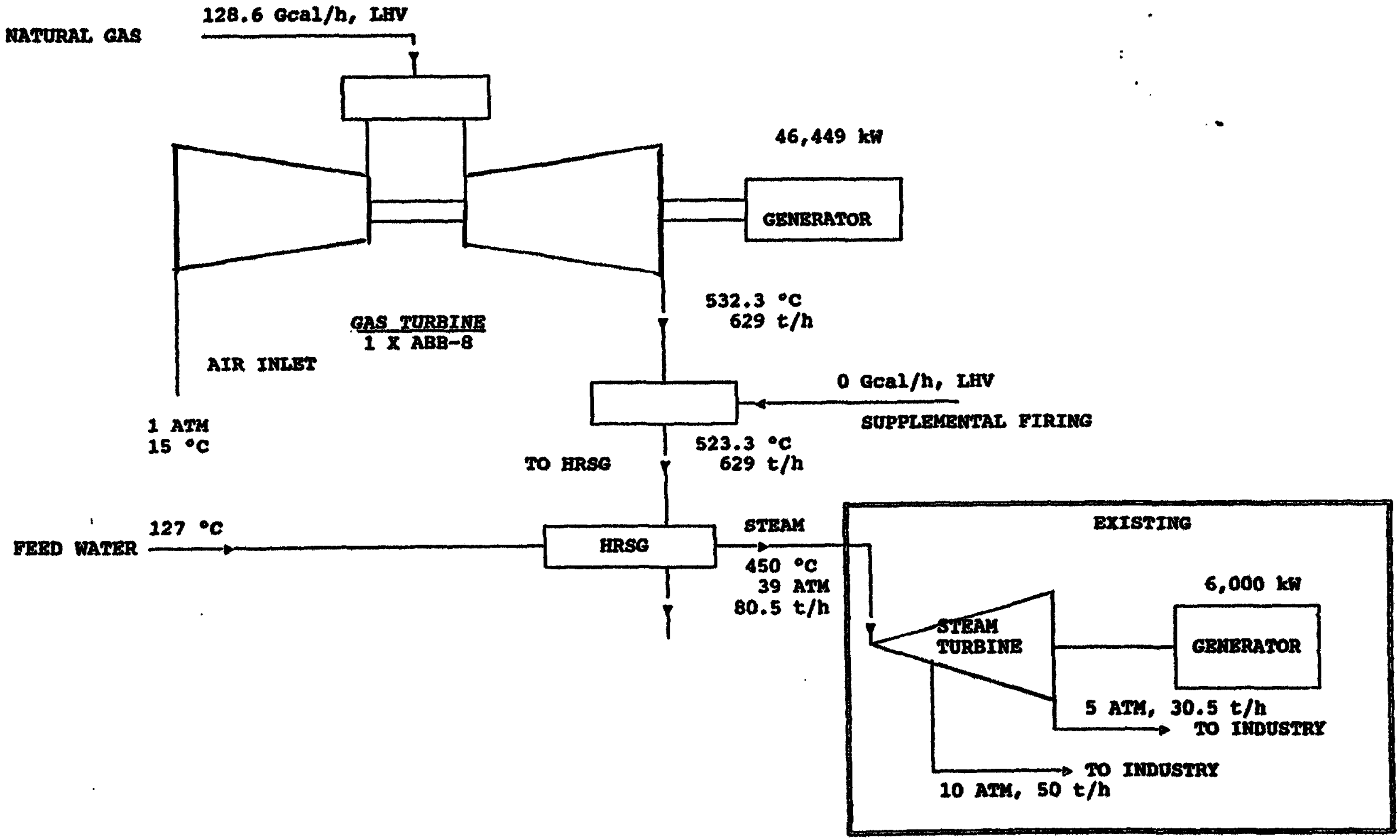


Figure 6.2.2

PLANT ⟶ SHUMEN UNIT ⟶ 2

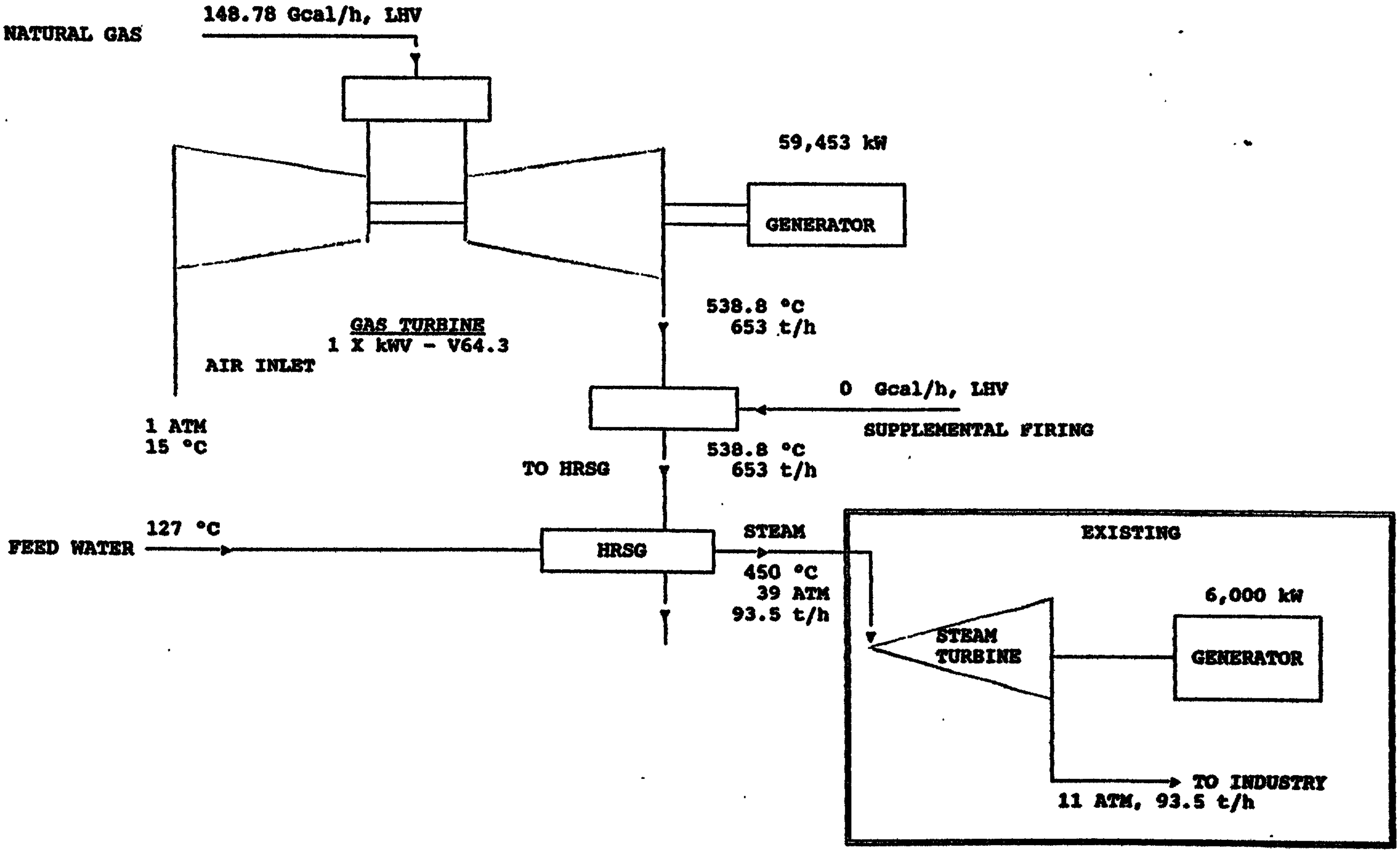


Figure 6.2.3

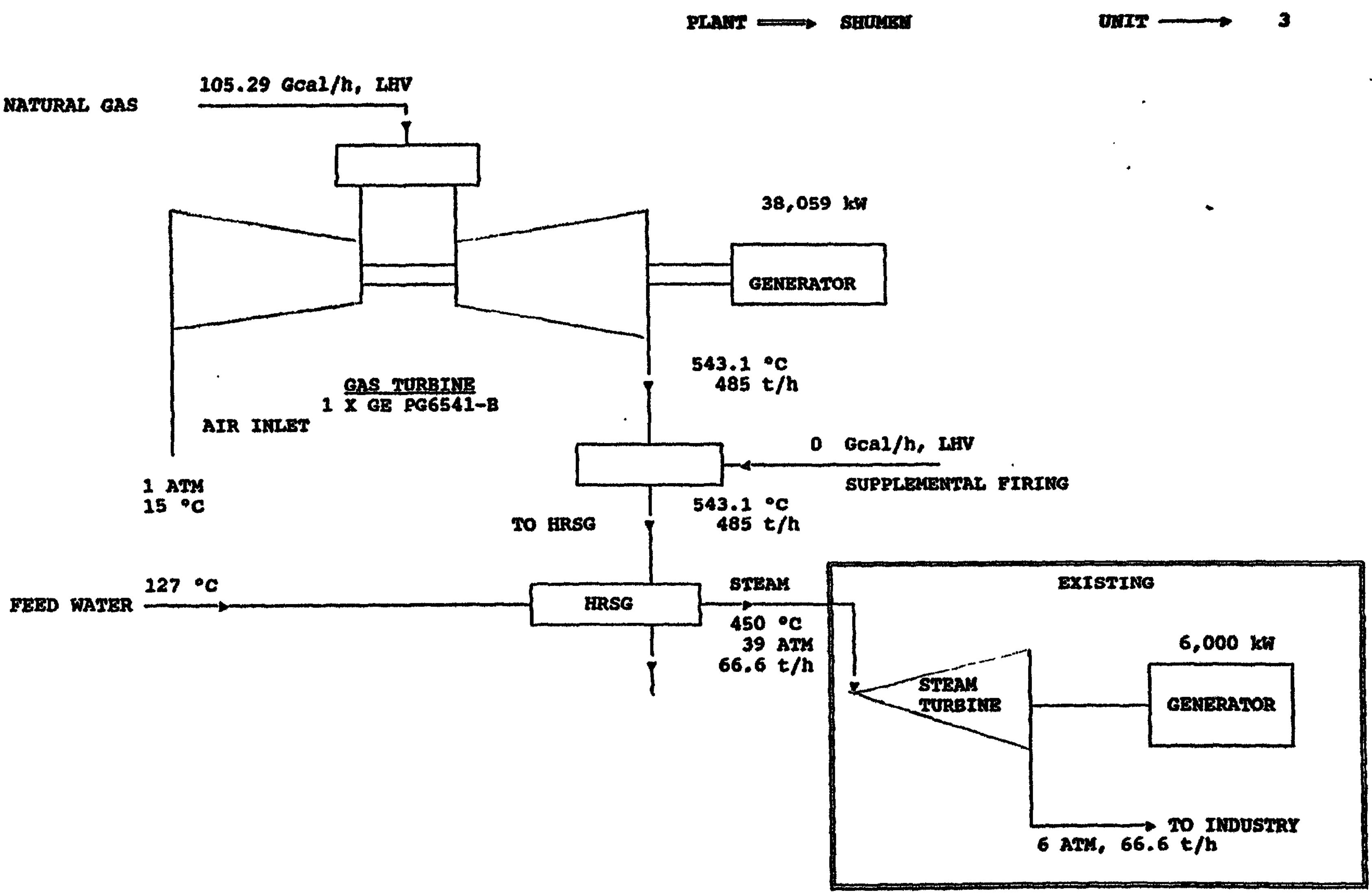

PLANT → SHUMEN
UNIT → 3
NATURAL GAS
105.29 Gcal/h, LHV
38,059 kW
GENERATOR
GAS TURBINE
1 X GE PG6541-B
AIR INLET
1 ATM
15 °C
543.1 °C
485 t/h
0 Gcal/h, LHV
SUPPLEMENTAL FIRING
543.1 °C
485 t/h
TO HRSG
FEED WATER
127 °C
HRSG
STEAM
450 °C
39 ATM
66.6 t/h
EXISTING
6,000 kW
STEAM TURBINE
GENERATOR
TO INDUSTRY
6 ATM, 66.6 t/h

Figure 6.3.1

PLANT ⟹ BURGAS UNITS ⟶ 1 & 2

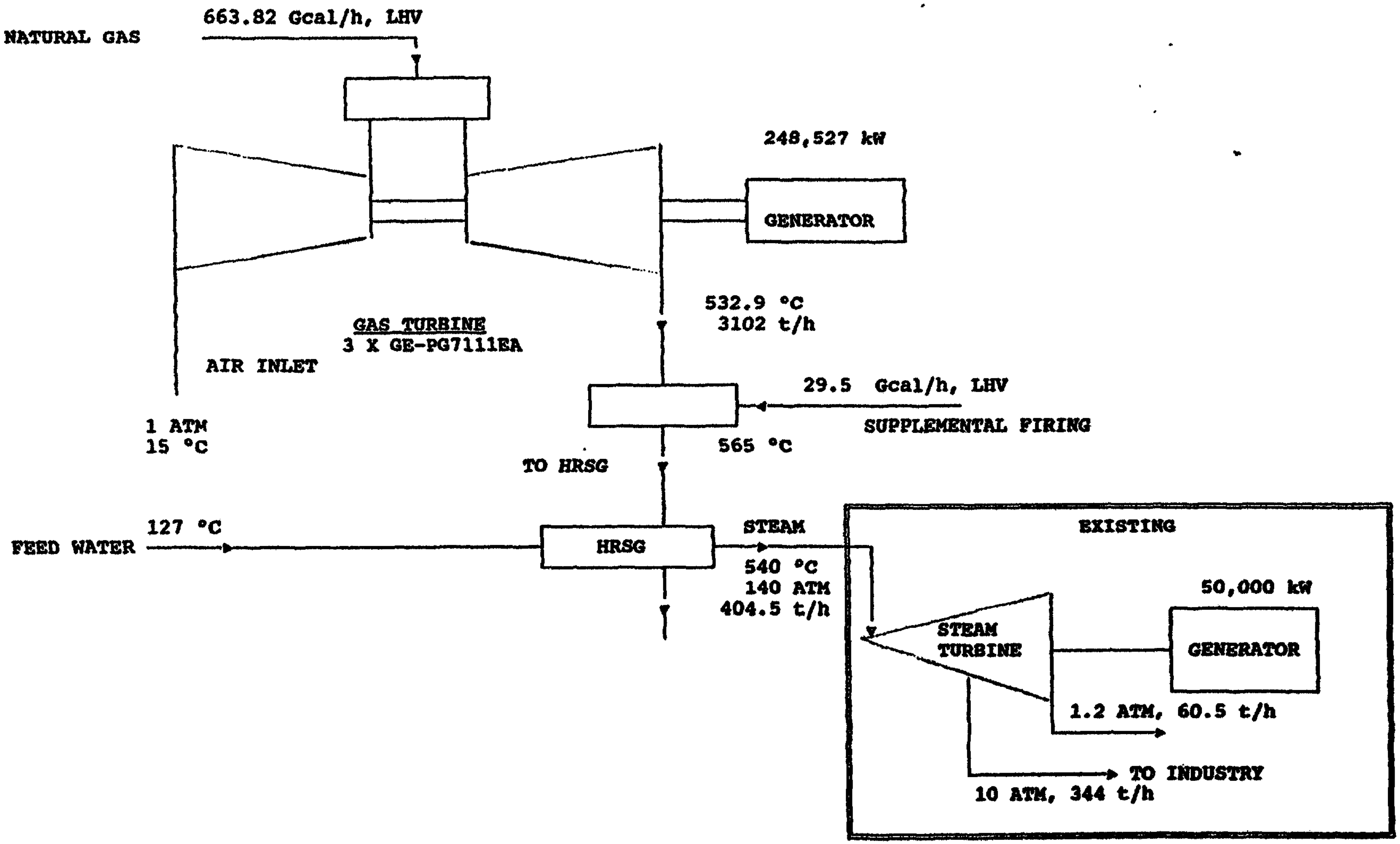
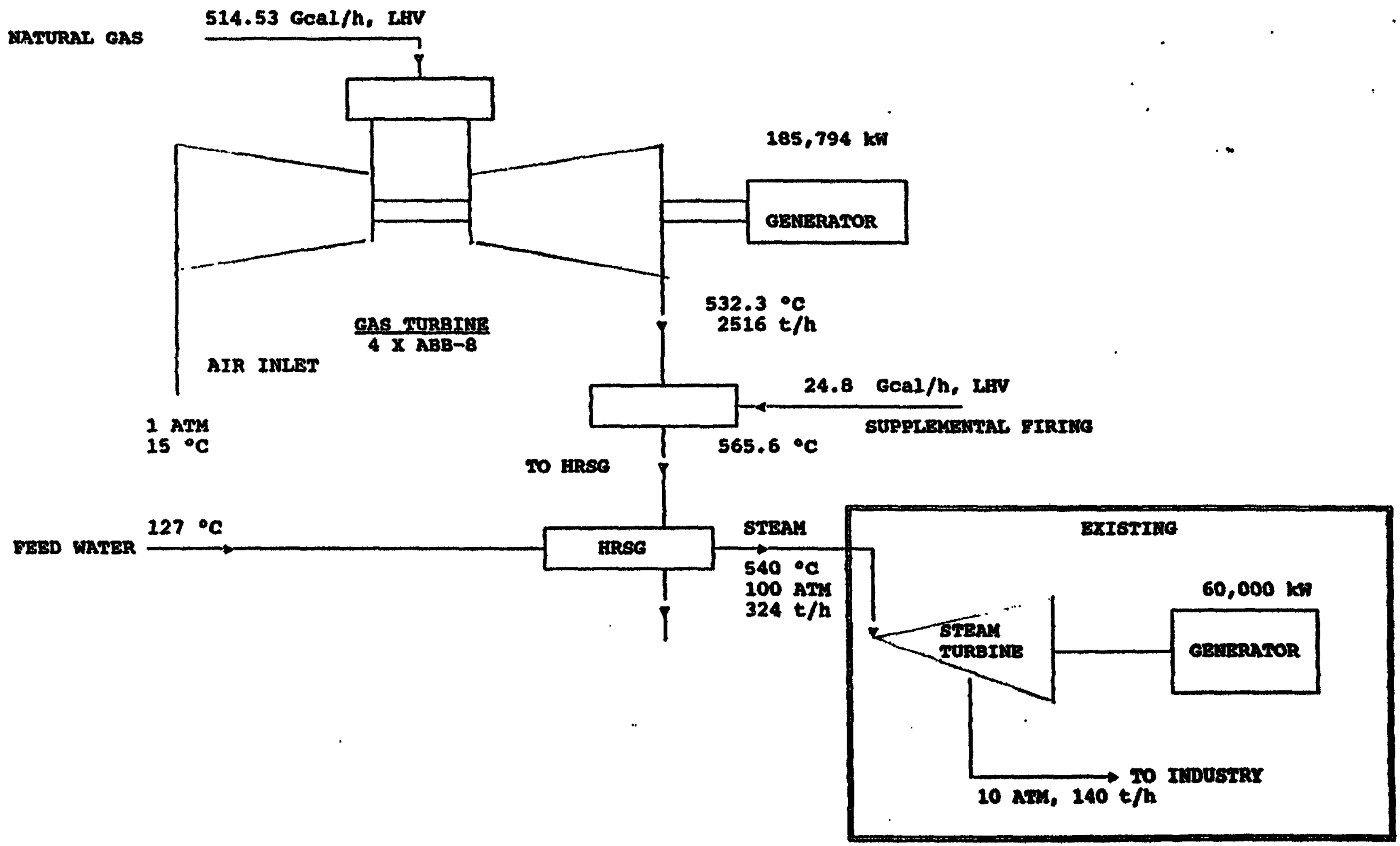


Figure 6.3.2

PLANT ⟶ BURGAS   UNITS ⟶ 3 & 4



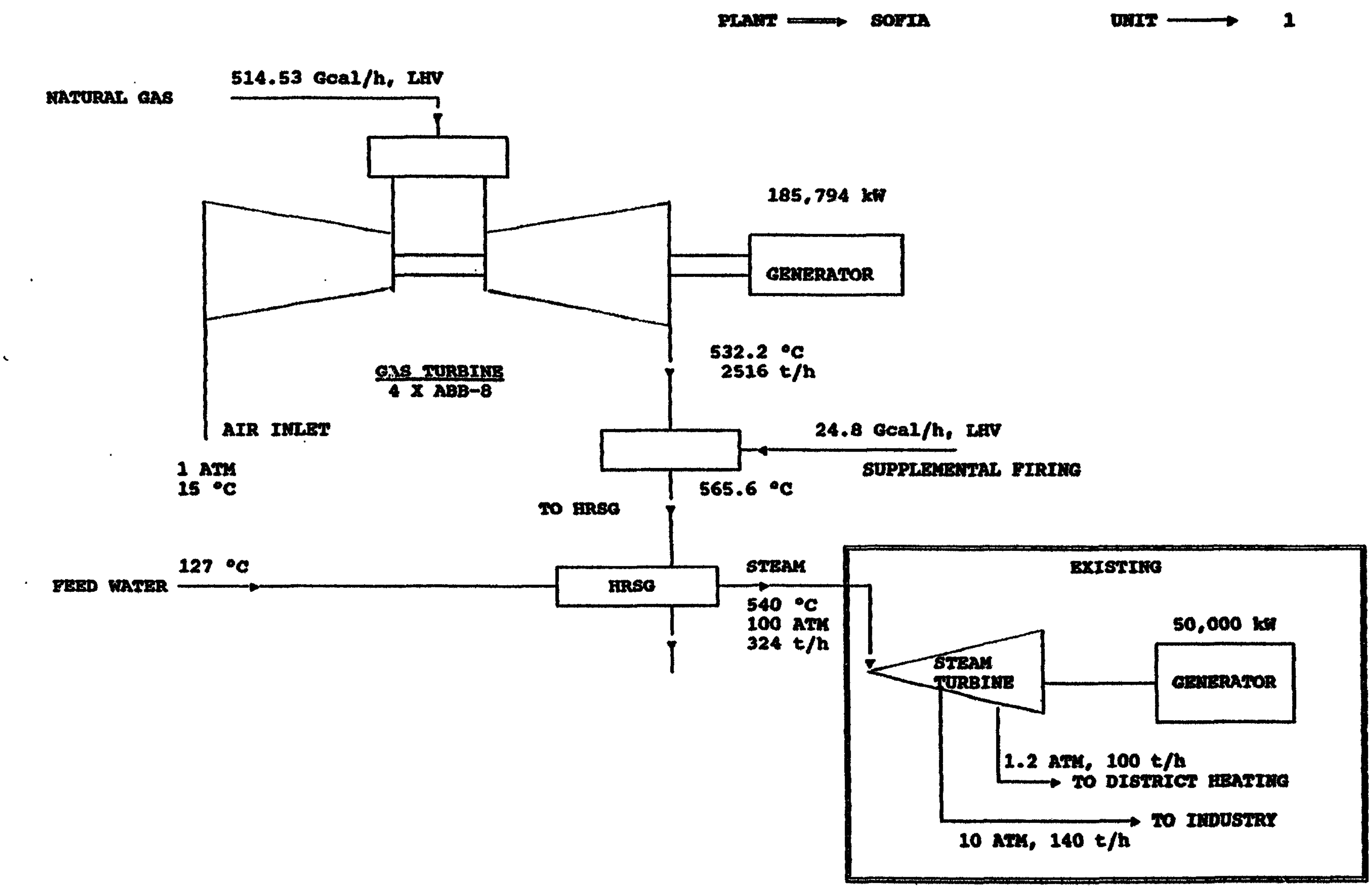
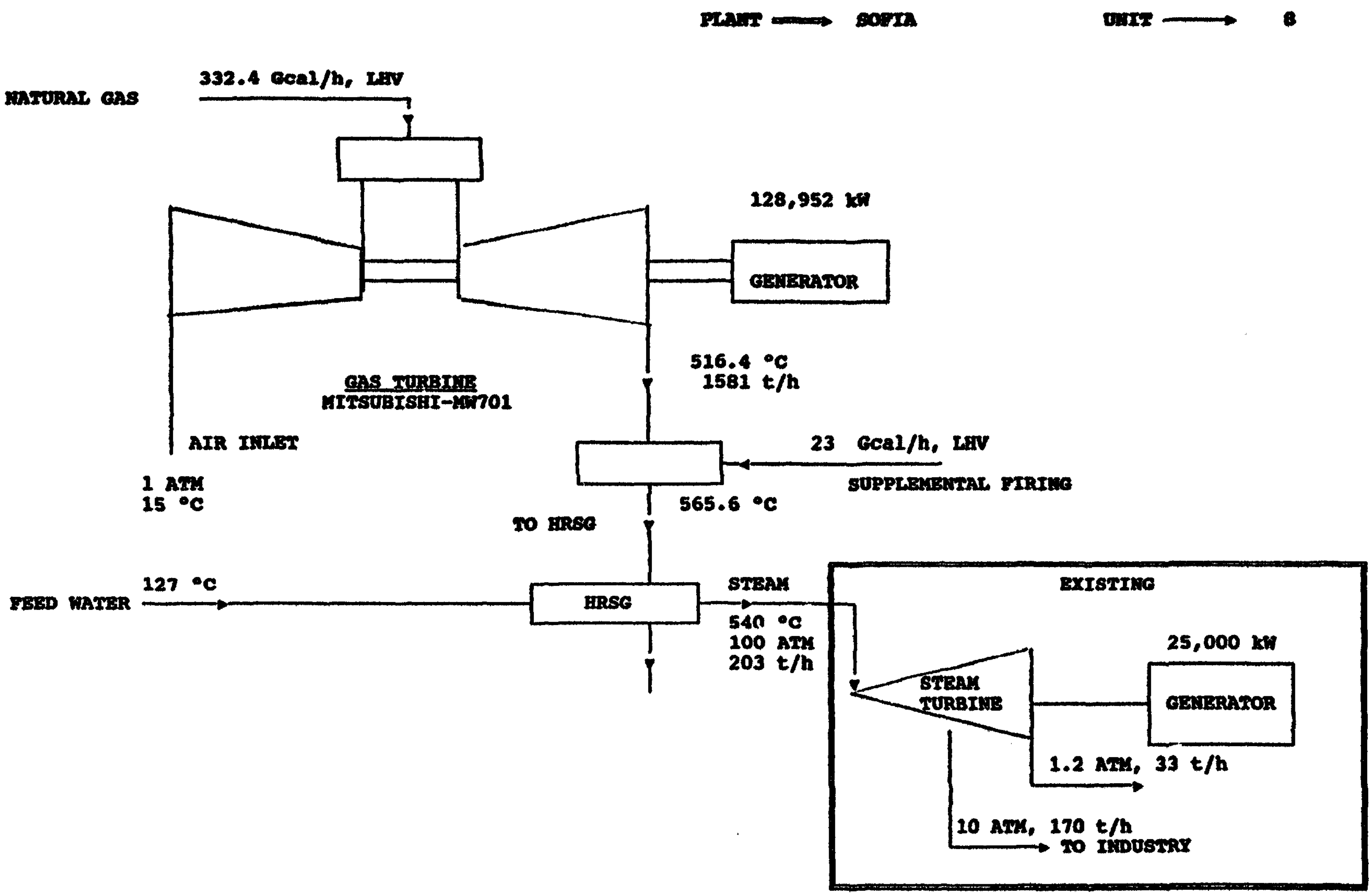
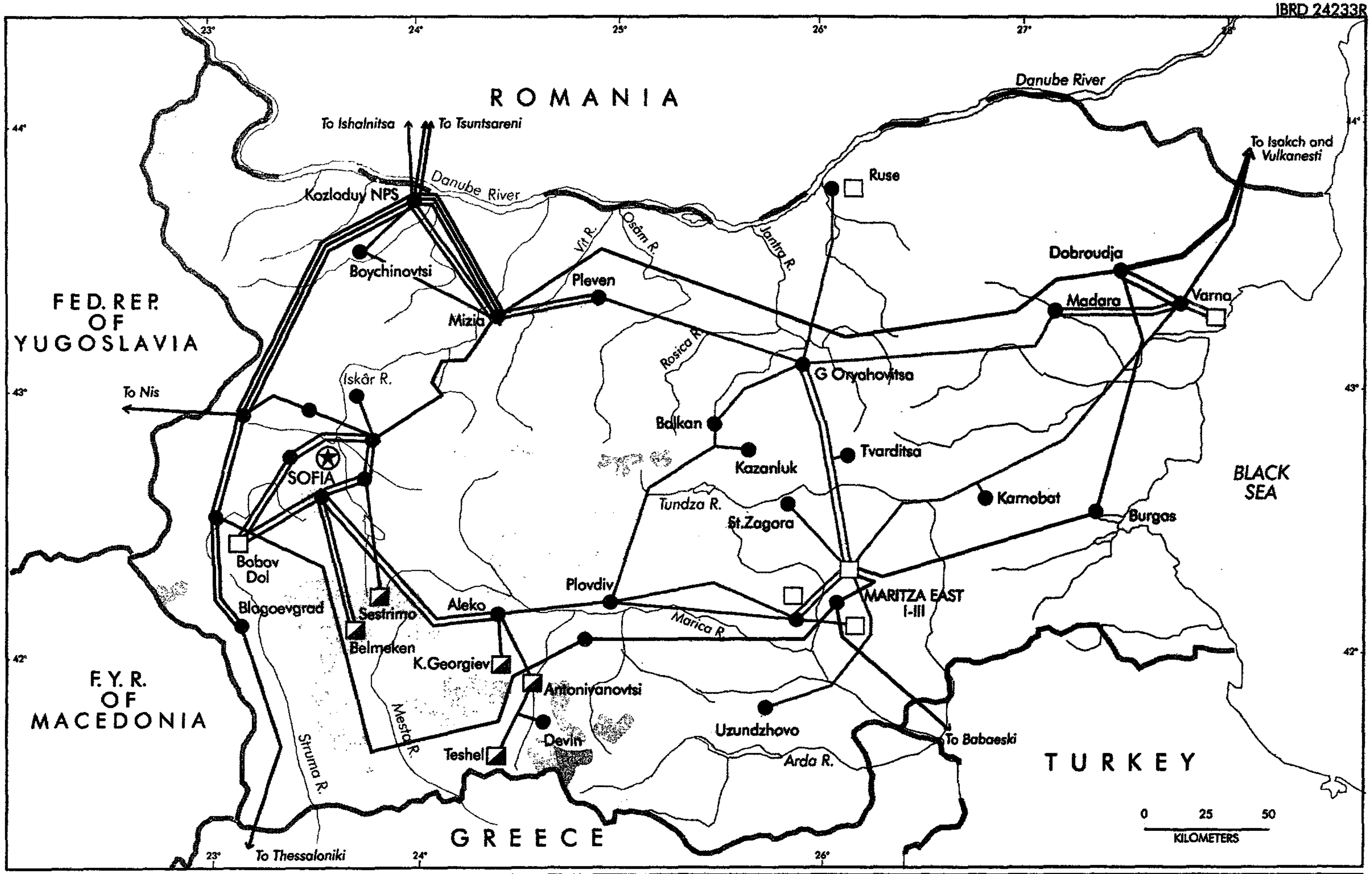

PLANT → SOFIA
UNIT → 1
NATURAL GAS
514.53 Gcal/h, LHV
185,794 kW
GENERATOR
532.2 °C
2516 t/h
GAS TURBINE
4 X ABB-8
AIR INLET
1 ATM
15 °C
24.8 Gcal/h, LHV
SUPPLEMENTAL FIRING
565.6 °C
TO HRSG
127 °C
FEED WATER
HRSG
STEAM
540 °C
100 ATM
324 t/h
EXISTING
50,000 kW
STEAM TURBINE
GENERATOR
1.2 ATM, 100 t/h
TO DISTRICT HEATING
TO INDUSTRY
10 ATM, 140 t/h

Figure 6.4.2


PLANT → SOFIA
UNIT → 8
332.4 Gcal/h, LHV
NATURAL GAS
128,952 kW
GENERATOR
516.4 °C
1581 t/h
GAS TURBINE
MITSUBISHI-MW701
AIR INLET
1 ATM
15 °C
23 Gcal/h, LHV
SUPPLEMENTAL FIRING
565.6 °C
TO HRSG
127 °C
FEED WATER
HRSG
STEAM
540 °C
100 ATM
203 t/h
EXISTING
25,000 kW
STEAM TURBINE
GENERATOR
1.2 ATM, 33 t/h
10 ATM, 170 t/h
TO INDUSTRY



BULGARIA

MAJOR ELECTRIC FACILITIES

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ELEVATIONS IN METERS:
2200
600
200
0

HYDRO POWER STATIONS
THERMAL POWER STATIONS
110 kV - 750 kV SUBSTATIONS

750 kV TRANSMISSION LINES
400 kV TRANSMISSION LINES
220 kV TRANSMIS. ON LINES

RIVERS
NATIONAL CAPITAL
INTERNATIONAL BOUNDARIES

MAY 1993